PETROLEUM PRODUCTION METHODS

JOHN R. SUMAN

H. L. Hamilton

PETROLEUM PRODUCTION METHODS

BY

JOHN R. SUMAN

SECOND EDITION

HOUSTON, TEXAS
GULF PUBLISHING COMPANY
1922

Oil Weekly Press
GULF PUBLISHING COMPANY
HOUSTON, TEXAS

PREFACE

This book has been compiled in a sincere endeavor to aid those men who are engaged in the business of drilling wells, operating producing properties or constructing pipe lines, tank farms and pumping stations. It has been the endeavor to get together in one volume a great deal of important data dealing with various phases of the petroleum industry, and thus to make accessible to the practical man a large fund of information which is only found in the transactions of the various technical societies. There is a real need for a book of this kind. Various books have been published in the past which devote a large portion of their contents to geology, accounting, refining, etc., but in so far as the author is aware no book has as yet appeared in print which has dealt specifically with the problems arising from the drilling of wells and the producing and handling of oil.

Much credit is due to men working for the larger companies in the southwest and in California for numerous helpful suggestions. Most of these men have requested that their names be withheld. Particular acknowledgment must be made, however, to those men who have written special articles for this book. Mr. J. A. Tennant, author of the article on the blowing of wells with compressed air, is the recognized authority in the southwest on this subject. The valuable discussion of the performance of rock bits in rotary drilling was written by Mr. Harold Fletcher, who is probably the most thoroughly informed man on this subject in the United States. Mr. H. R. Lucke who presents the article on Diesel engines in their application to pipe line pumping stations, is an engineer whose ability is recognized throughout the Southwest. Acknowledgement is also made to the numerous authors who have given permission for the reprinting in this book of their valuable articles. The various oil-well supply, tool and electrical supply companies have been extremely kind in furnishing tables, cuts, and interesting performance data.

No hesitancy has been felt in reprinting, verbatim, from various published data, a great deal of material which seemed likely to be

of assistance to men confronted with the particular problem in question. Excerpts from the publications of the United States Bureau of Mines and the American Institute of Mining and Metallurgical Engineers have been reproduced throughout the book in this connection. Full credit is given to all authors and publishers and special permission has been secured for the use of all such material.

Strict economy and rigid efficiency methods are matters which, in the past have been given but little attention in the petroleum industry. It is quite probable that as time goes on the production of petroleum per well in the United States will gradually decline to the point where operators will become very much interested in doing things in a more efficient manner. If, through reference to this work the industry is enabled, in some degree, to work more efficiently and economically the author will feel that his effort has been adequately rewarded.

JOHN R. SUMAN.

HOUSTON, TEXAS
July 1, 1921

CHAPTER I

DRILLING METHODS

CHAPTER II

METHODS OF SHUTTING OFF WATER

CHAPTER III

OPERATION OF PROPERTIES AND HANDLING OF PRODUCTION

CHAPTER IV

TREATING EMULSIONS

CHAPTER VIII

TABLES AND USEFUL INFORMATION

PETROLEUM PRODUCTION METHODS

CHAPTER I.

DRILLING METHODS

SELECTION OF METHOD OF DRILLING.

Introduction.—The fundamental or basic operation concerned with the petroleum industry centers in the technical problem of the drilling of wells. These wells may vary in depth from 90 to 6000 or 7000 feet, and the relative cost and care exercised with their drilling generally increases directly in proportion to the depth. One can appreciate the vastness of this part of the petroleum industry when it is remembered that in the year 1920 no fewer than 35,000 wells were drilled in the United States alone. It is estimated that these wells cost in the neighborhood of 575,000,000 dollars.

Starting with the primitive method used in 1859, in Pennsylvania, the technique of well drilling has advanced by leaps and bounds, but it is the common opinion among operators that there is still much room for improvement. In the development of methods of drilling in the United States two systems have been evolved. The earliest system to be employed was the standard cable tool system which was developed in Pennsylvania and West Virginia, and later brought to a high stage of perfection in California. The other system known as the rotary system was developed in the drilling of wells into the soft and cavey formations of the Texas and Louisiana coastal plain.

In many fields of the United States the matter of selection of method of drilling is very seldom considered, as there is commonly only one method which is at all feasible. For instance, in the gulf

coast fields of Texas and Louisiana, the rotary system of drilling is used exclusively, and in its present state of development no one would consider the use of cable tools. In West Virginia and Pennsylvania as well as in Ohio, Indiana and Illinois, the cable tool system of drilling is employed to the exclusion of the other system. Also in certain parts of Texas (Ranger and Breckenridge fields), the cable tool system of drilling has been found to be the only practical system for the efficient drilling of oil and gas wells.

In other fields it has been found that either system of drilling can be used and usually in such fields both systems have their very strong adherents. It has been found that in certain parts of California, in Mexico, and to a certain extent in parts of Oklahoma that wells can be drilled by either system or by a combination of the two. In such cases the relative merits of each system must be given careful consideration. Johnson and Huntley[1] have summarized the various points in favor of and against each system as follows:

COMPARISON OF DRILLING SYSTEMS.

Cable system. Advantages.—

1. Less first cost of tools and rig.
2. Lower labor cost per day.
3. Less water necessary.
4. Can drill in the hardest rock.
5. More drillers available in some fields, although this is becoming less true.
6. Gives more information as to the formations passed through, and is thus better for prospecting.
7. Less cost per foot for relatively shallow wells.

Disadvantages.—

1. Longer drilling time.
2. Much slower when under-reaming is necessary.
3. Danger of delays and fishing troubles in soft strata.
4. When many water sands, hard to carry large hole to deep pay.
5. Greater cost per foot for moderately deep wells.
6. More casing necessary to handle caves and water sands.
7. Liability of getting crooked hole in soft formations.
8. Harder to control heavy pressures and more likelihood of "blow outs."

[1] "Oil and Gas Production Methods."—Wiley.

Rotary system. Advantages.—

1. Faster drilling in soft strata.
2. Less trouble from caving and water sands.
3. Less casing used in soft formations with water and gas sands.
4. Straighter hole in deep drilling soft formations.
5. Can handle alternate hard and soft formations, with less danger of of accidents than with cable tools. This is made possible by the new bits and heavier rotary machines.
6. Can carry a large hole deeper.
7. When "drilling in," easier to control high gas pressure and prevent blowouts.

Disadvantages.—

1. Very slow in hard strata.
2. Greater daily labor cost.
3. Limited trained labor supply in some fields.
4. Greater cost per foot for shallow wells.
5. Does not show up smaller oil and gas pays, and important reservoirs may be passed through in prospecting.
6. More water necessary, a drawback in arid regions.

In certain fields where soft, unconsolidated sands are encountered, such as in California, the question of the better method of drilling to select is a very common subject for argument. Mr. Wm. Kobbe has summarized the relative merits of each system very nicely as follows:[1]

The selection of a drilling method is based on the following considerations: (1) Character of the formations overlying the reservoir; (2) thickness of the oil-bearing stratum or strata; (3) thickness and character of water or gas sands; (4) gas pressure to be encountered or expected; (5) total depth of well.

Character of the formations overlying the reservoir.—The strata overlying the reservoir may consist of beds of shales, clays, sands and other soft materials or they may be slates, limestones and sandstones consolidated to all degrees of hardness. Very often the overlying strata are predominantly of soft materials but interbedded with harder formations. Likewise, soft strata are encountered at different horizons in an overburden consisting almost entirely of the harder sedimentaries. The physical character of this overburden is frequently complicated by the occurrence of quicksands, gypsum, rock salt or iron pyrites.

If it is known that the overburden consists of predominantly soft and cavey material, such as sands, clays, soft shales, quicksands, beds of gypsum,

[1]Transactions A. I. M. E.—"Recovering Oil From Unconsolidated Sands."

etc., a rotary drilling rig of a size and type commensurate with the depth would be the most efficient method of overcoming such conditions.

On the other hand, if it is known that the overburden consists of predominantly hard strata such as limestones, sandstones, hard shales and slates, cable-tool equipment would be employed and a standard rig, with or without calf wheels, erected.

In many parts of the world it is impossible to classify the overburden either as predominantly soft or as predominantly hard. It is made up of many strata of each class. Such conditions are typical of the deep and difficult drilling in certain parts of California, for example at Fullerton and in portions of the Midway district. The only efficient method of drilling wells through 3000 or 4000 feet of these mixed strata is the combination system employing both cable and rotary on the same rig. A heavy combination equipment, with a 24 by 112-foot derrick, iron crown block, latest type of draw works and large rotary, frequently costs as much as a completed well located in the comparatively shallow portions of the Mid-Continent or Eastern fields.

Thickness of the oil-bearing stratum or strata.—The thickness of the unconsolidated pay sand that must be penetrated is an important factor in the selection of the drilling system. One hundred feet of loose oil sand carrying even a moderate gas pressure often necessitates the use of rotary equipment notwithstanding the fact that a decision based solely upon the physical character of the overburden would select cable tools for the work. For example, in the extreme northern portion of the Midway field in the San Joaquin Valley, California, there is 700 feet of predominantly hard cable tool overburden which must be penetrated in order to reach an unconsolidated oil sand 280 to 300 feet thick. Experience has shown that the rotary drilling method completes a well in that district in half the time and at less cost than cable tools. This for the reason that the former system averages more hole per day from top to bottom than the latter although more time is required by the rotary to reach the sand. The cable tools have no difficulty in "making hole" through the 700 feet of predominantly hard overburden but encounter the greatest difficulty in making headway in the oil sand. In fact, the heaving nature of these sands causes innumerable fishing jobs and frozen strings of casing when an attempt is made to overcome them with cable equipment. After fighting them for weeks, if the standard driller has 200 feet of pay to his credit he is doing well, whereas the same driller on a rotary rig can wash through the 300 feet of sand in one tour of 12 hours.

These conditions indicate the important bearing the thickness of the unconsolidated pay sand has upon the problem of selecting a drilling system.

A few miles south of the area just described the oil sand is only 10 feet thick and underlying similar formations of hard strata. Here the cable tools are far superior to the rotary because they can readily overcome the

thin bed of pay sand and are better adapted to drilling through the overburden.

Thickness and character of water or gas sands.—Cable tools are superior to the rotary for prospecting new territory and for determining the exact depth of water- or gas-bearing horizons. It sometimes happens that an area or pool has been inefficiently developed and exploited; that available well records are unreliable, or that the lenticular nature of the sands causes great uncertainty regarding the exact depth of water strata. Under such conditions it is advisable to employ cable tools until all necessary data have been obtained, when the drilling method may be advantageously changed to the rotary. Conditions such as these at one time existed in portions of the Burkburnett field in northern Texas and although it was known that the territory was particularly adapted to rotary drilling it was necessary to "feel out" from proven areas with cable tools on account of the "spotted" nature of the oil and water sands.

Gas pressure to be encountered or expected.—Gas pressure is a factor of the utmost importance in the selection of a drilling system. Other things being equal, the greater the pressure the greater its importance; not only from the mechanical standpoint but to serve the ends of conservation. This pressure may occur above the oil reservoir, within the reservoir, or both. When it is known to occur above the oil sands it may be cased off with cable tools and conserved between strings of casing by the use of a packing spider, a special device which has met with great success in the deep and high-pressured territory of southern California.

Where high gas pressures exist in formations difficult for a rotary to overcome it frequently becomes necessary to utilize special methods in conjunction with the cable system to properly cope with the situation. For example, the mud-laden fluid method and circulator systems may be called to the aid of the cable tools in passing through strata under high gas pressure.

The rotary system, however, is the ideal method of overcoming gas sands and should be employed wherever it is possible to drill by this method. In portions of the north Midway field the pressure within the unconsolidated and very loose oil pay is sufficient to heave the sands 200 to 300 feet up in the casing of cable tool wells unless special safeguards are introduced, whereas the rotary with its column of mud slip penetrates these sands with the greatest ease and dispatch.

Total depth of well.—As has already been pointed out, the character and thickness of the oil sand often modifies the selection of any particular drilling method but the same sand at 1000 feet requires lighter equipment and possibly a different system than if it occurred at 4000 feet. The former may be easily reached with cable tools and a 20 by 84-foot standard rig while the latter may require the heaviest rotary or combination equipment.

THE ROTARY SYSTEM OF DRILLING

General notes on the rotary system.—The rotary system of drilling was developed in the oil fields of Texas and Louisiana, where, in a space of about eighteen years over 20,000 wells have been successfully drilled with it, which would have been impossible with any other system, owing to the peculiar nature of the formations encountered. These formations were very unconsolidated and soft and caving. The rotary system of drilling is, however, equally adaptable for work in deep territory where thick strata of extremely hard rock must be penetrated. This has been fully verified in the California fields, some of which are admitted to be as difficult to drill as any in the world.

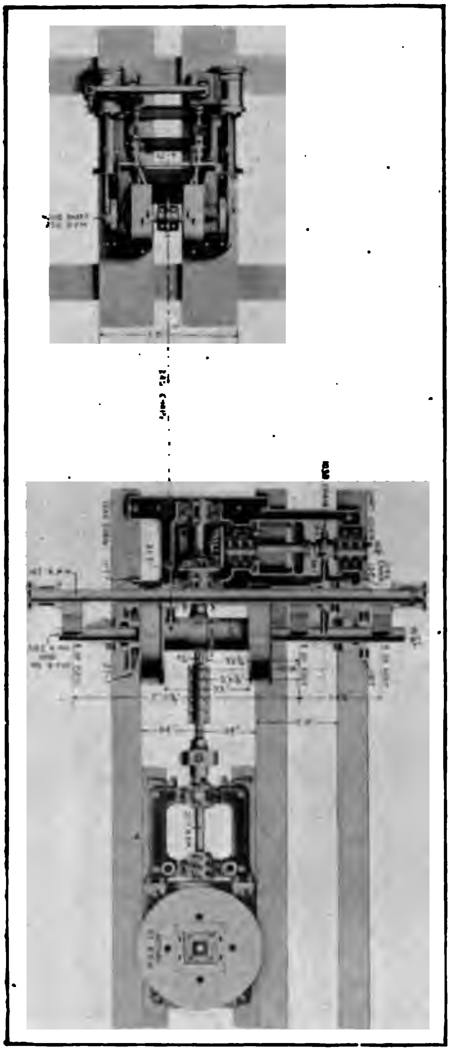


Fig. 1.—Diagram of Shaft Driven Rotary.

The expense involved by having to use several strings of casing in one well is a matter of serious concern to operators. This problem has been solved by the introduction of the rotary, and today in the California fields wells are commonly sunk to a depth of 3000 feet with one string of 10-inch casing.

A speed of 100 feet per day of 24 hours is not unusual in favorable territory, and much better records

have been made with improved machinery. In the Humble, Texas, field as much as 750 feet of hole has been made in one day. In the Batson, Texas, field where one producing sand is found at 350 feet, wells have been drilled, casing and strainer set and the well made ready for bailing in one day. In the Saratoga, Texas, field it is not considered unusual for a crew to make 450 feet of hole in one day using improved rotary machinery.

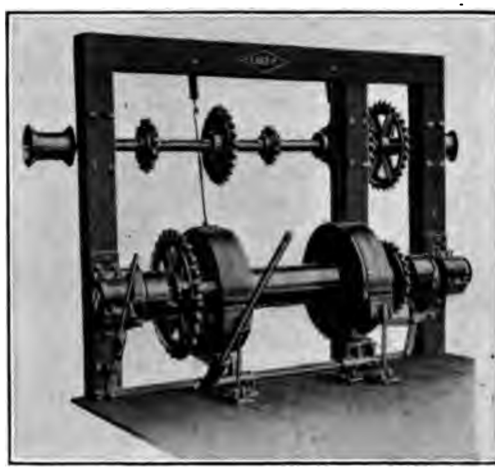


Fig. 1-a—Standard Rotary Draw Works.

Fishing jobs with the rotary system are relatively few and ordinarily of a very simple kind. When one considers the thousands of different kinds of complicated fishing jobs which are apt to be encountered when drilling with the cable tool system, and the great expense caused by them, it is easily seen that the rotary system is to be preferred in all territory where it will go at all.

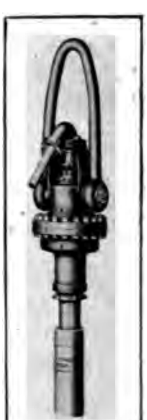


Fig. 2—Rotary Swivel

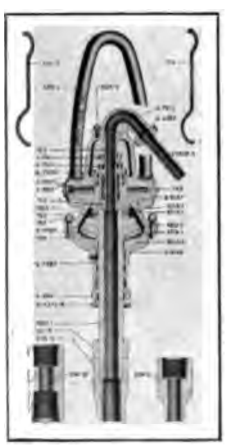


Fig. 2-a—Sectional View of Rotary Swivel

Description of process.—The essential difference between the rotary and cable tool systems of drilling is that the hole with the rotary system is made by the constant rotation of the bit upon the formations, drilling them out in much the same manner as a hole is drilled in a piece of wood or iron, by a bit, instead of hammering upon the formation and thus breaking it into small particles by

the reciprocative motion of the string of tools, as used in the cable tool system. The rotary bit attached to the bottom of the drill pipe is rotated by means of a rotary gripping device. A grief stem or "kelly joint" is attached to the upper part of the drill pipe and works in the gripping device. This gripping device is so constructed that it permits the drill stem to slide down as the drill penetrates the strata below and enables the drill to be lifted off bottom while rotating, if necessary. This rotation of the bit upon the formation drills a hole in the rock without jar or shock to the strata, thus eliminating any caving tendency. In addition to this, any loose formation is held back and prevented from caving by the pressure of a column of mud of varying consistency, according to the formation being passed through, which is pumped down through the drill stem, circulating from the bottom of the hole back around the drill stem to the surface, thereby plastering the wall. This mud emerges in streams of high velocity from two holes in the bit, and strikes against the formation being drilled. Upon its return to the surface it carries with it the cuttings, which, owing to the reduced velocity, are deposited in the mud trough during the course of the mud from the flow line, back to the pump or "mud pit," before the mud is again forced to the bottom of the well and again circulated.

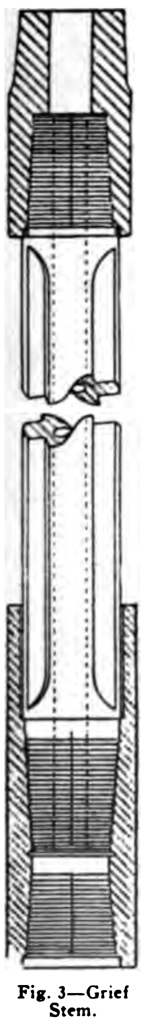


Fig. 3—Grief Stem.

Drill Mud.—The mud solution is made by mixing clay with water to the desired consistency, which is stored in a pit and conducted into the "slush pit" from which the pump draws its supply as wanted. By having a good supply of mud on hand, and altering its consistency, and the speed of the pump which regulates the velocity of the stream, perfect control over high pressure strata, which may be encountered very unexpectedly, is insured. In loose caving formations where no pressure is encountered, it is only necessary to thicken the fluid to prevent caving.

Method of drilling.—To pump mud through the drill stem a swivel (See Fig. 2) is used which is

screwed into the top of the drill stem and is suspended from the casing block by means of which the drill stem is raised or lowered at will, and by means of which the pressure on the bit is controlled. The pump delivers its stream of mud to the drill stem through the swivel, to which it is connected by a flexible hose. The swivel and drill stem are suspended from the crown block by means of hoisting lines passing through the traveling block, the connection being made by means of a strapped C-link and double swivel casing hook (See Fig. 5). The hoisting line passes over the sheaves in the crown block at the top of the derrick and down to the hoisting drum, the multiplication of pulleys being made necessary because of the great weight of the long drill stem. These same hoisting lines and blocks are used also for the raising or lowering of casing.

The rotary table is driven, in the older model rotaries, by means of a chain passing over the sprocket wheel of the rotary pinion shaft and the line shaft of the draw works. A newer model rotary is shaft driven as shown in Fig. 1. The line shaft of the draw works in turn is driven by means of a chain passing over a sprocket on this shaft and the crank shaft of the steam engine. The line shaft is equipped with two other sprockets, which, by means of the chain connection, drive the hoisting drum, and the ratios of the diameters of these sprockets are such that two speeds may be given to the hoisting drum. This gives a slow speed for heavy hoisting and a fast speed for quick hoisting, either of which may be used by the simple engagement of corresponding clutches under the control of the driller. There is also a clutch on the drum shaft which permits the driller to bring all the mechanism to a standstill with the exclusion of the engine sprocket. Catheads are mounted on either end of the line shaft for use in hoisting with a rope or for operating the tongs when setting up or unscrewing the drill stem joints or for making up the tool joints. Control of the position of the drill stem or of the lowering of casing is secured by means of asbestos-lagged brakes engaging with the iron braking sur-

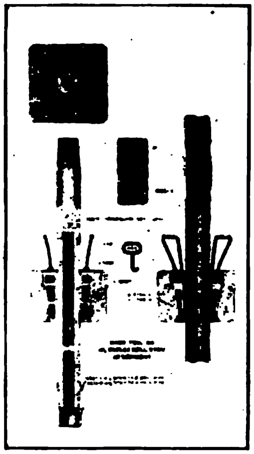


Fig. 4—Square Grief Stem Showing Method of Operation, also Method of Holding Drill Pipe in Spider.

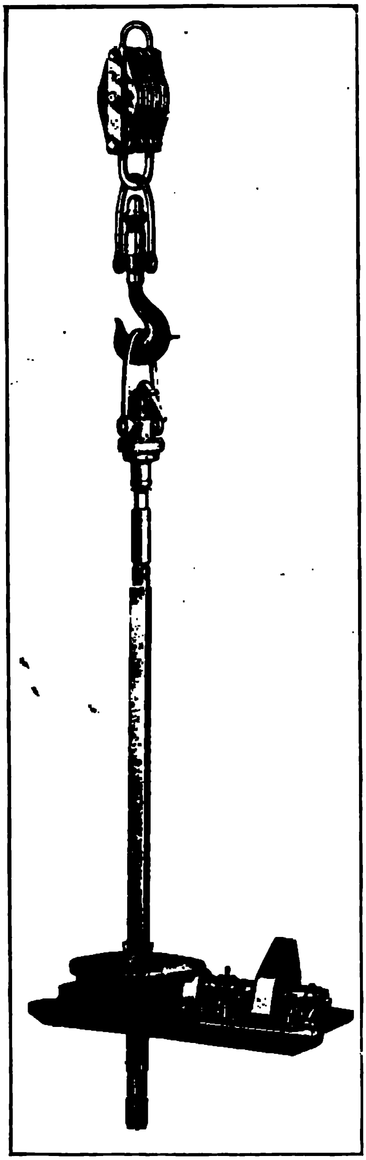


Fig. 5—Rotary drilling outfit showing assembly of rotary machine, grief stem, swivel, wigle spring casing hook, and travelling block.

face of the drum. The brake lever is conveniently placed so that the action of the brakes may be controlled by the driller who stands at the right of the draw works, facing the rotary table. The engine reverse lever, throttle cord, and drum clutch levers are all conveniently located, thus enabling the driller to maintain perfect control over the drilling operations at all times.

Removing drill bits. — It is at once apparent that the only necessity arising for the removal of the drill stem arises when it is necessary to resharpen the drilling bit. This is accomplished by withdrawing the stem until the first tool joint is above the rotary table when the slips are placed in the drive bushing to keep the pipe from dropping. Tongs are then placed about the two sections on the tool joint and the "grief" stem is unscrewed, pushed to one side and lowered into a "rat hole" made by rotating two joints of 8-inch pipe under the derrick floor. The swivel is left attached to the upper end of this first joint of the drill stem, or the "grief stem" as it is commonly called. The block and hook are then lowered and inserted into the links of the elevators which are thrown around the projecting pipe and the stem is elevated into the derrick until the next tool joint (which may be placed at every three or four lengths in the

drill pipe) emerges above the top of the rotary table, when the same operations are repeated—the joint is broken and the 60 or 80-foot lengths of drill pipe (called "thribles" and "fourbles" by the drillers) are stood up in the derrick to one side of the rotary. This process is repeated until the bit reaches the surface when it is unscrewed and another bit, which has been sharpened, is quickly attached and the pipe is again lowered to the bottom of the well and drilling resumed. The entire process of pulling out, putting on new bit, and going back into the hole may be accomplished in about six hours in holes as deep as 3000 feet. In ordinary formations a fish-tail bit will drill for about 24 hours without needing resharpening.

Some objections to the rotary system.—It is sometimes claimed that owing to the great rapidity with which hole is made with the rotary that small oil showings are passed up without being noticed. Such a thing could only occur under the control of a careless and inefficient driller, as shown later under the discussion of sampling.

Another objection is the possibility of flooding the oil sand with water. The very fact that the quantity of solution is limited and circulated in a continuous stream, and diminution in this quantity, which would be caused by some of it passing into an oil sand, would be detected immediately by the driller. He would immediately thicken up his mud so that the sand would be plastered up instead of filled with water. In this way oil, gas, and water sands can be controlled and brought in as desired.

The Method and Cost of Drilling in Northern Louisiana[1]

Owing to the soft formation encountered in the wells in the North Louisiana field, the rotary system alone has been found practicable, according to an article in The Oil Weekly.

In the Claiborne field.—Drilling in the new Claiborne field is a simple process, especially in the shallow sand, in which a well can easily be completed inside of 30 days. Three distinct sands have been discovered in the Claiborne field, one at 1100 feet, one at 1400 feet, and one at 2100 feet. The 2100 foot

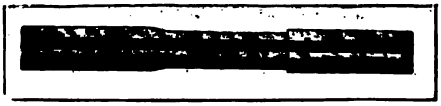


Fig. 6—Rotary Drill Collar.

[1]Published by permission of The Oil Weekly.

underlies the 1400-foot sand, no exploration having as yet been made under the 1100-foot wells. If a deep sand is discovered under the 1100-foot stratum at all comparable with the productivity of that discovered under the 1400-foot stratum, it is believed that it will be found to excell anything yet discovered in this territory.

It is estimated that a shallow well in the Claiborne field can be drilled for approximately $8000, and a deep well for $12,000.

The pool is located in a hilly country which drains quickly, and is situated comparatively close to a base of supply. The shallow depth at which the oil is found in this territory is a decided advantage, it being a well known fact that most of the difficulties begin after reaching a depth of 2000 feet.

In Bull Bayou field.—In the Bull Bayou district, where the production is found at a uniform depth of about 2725 feet, a "turn-key job"—that is, a completed well with casing and liner and master gate capable of withstanding 1600 pounds pressure, should cost approximately $18,000, and contracts are frequently taken at this figure, although unforeseen accidents and delays may bring the cost up to a much higher figure.

Drilling system.—Following the erection of the derrick and the preparation of the pits for holding the mixture of mud and water, the well is started with a 13-inch bit on the end of a 6-inch drill

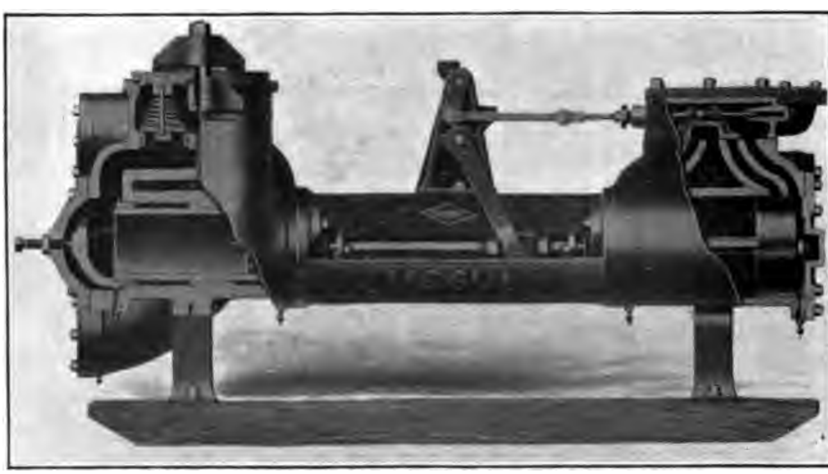


Fig. 6-b—View of 10x5¾x12 Mud Pump.

stem, and the hole is drilled to a depth of 250 feet. Here 10-inch casing is set and cemented and drilling is continued down through the gas sand with a bit 9⅞ inches in diameter to about 1050 feet, when the size of the hole is reduced to 8½ inches, without cementing the casing except in case of caving holes or bad fishing jobs.

Drilling is then continued to a depth of 2500 feet with an 8½-inch bit on a 4½-inch drill stem, when the 6-inch casing is set and cemented and the well is ready to drill in, which is done with a 5⅞-inch bit and a 3-inch drill stem, down through the oil sand.

After completing the hole to its total depth, which in this territory is from 2725 to 2740 feet, liner is set, consisting of four joints of blank 4½-inch pipe and eight joints of perforated pipe. through which the gas and oil enters from the oil sand and comes up through the hole, which is now lined from top to bottom with solid steel pipe or casing.

Ready to bail.—The well is now ready to bail, and the bailer, consisting of a length of 3-inch pipe with a valve in the bottom, is let down into the hole and drawn up and emptied into the slush pit, this operation being repeated until all the mud and water has been cleaned out of the hole and the oil permitted to flow through the perforated liner and up to the top of the well. In the majority of cases, in this district, the gas pressure is so great that the hole cleans itself out, and the well starts to flow as soon as the oil sand is reached.

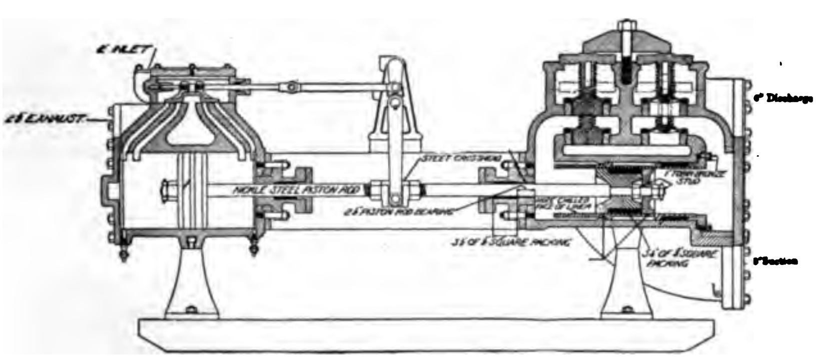


Fig. 6-c—Sectional View of 12x6¾x14 Mud Pump.

Following is a complete list of materials and tools required for drilling a well in the North Louisiana field:

Material required.—

Drilling Machinery. —

1—50 H. P. Boiler
1—Rotary
1—Draw Works
2—Pumps 10x5¾x12
1—48" Three-Sheave Traveling Block
1—8" Five-Sheave Crown Block
1—Grief Stem
1—6x4x6 Bulldog Pump
1—⅞"x1000' Drilling Line
1—4" Strapped "C" Hook
1—4" Drilling Hook
2—3" Swivels
1—⅝"x3500' Bailing Line
60—Feet 1030 Chain
40—Feet 1240 Chain
2—6" Foot Valves
2—6" Ells
2—6"x12" Nipples
1—2"x32' Rotary Drilling Hose
1—Set 2" Hose Clamps and Nozzles
1—Mogul Tong with 6" and 4" Jaws
1—Lighting Machine with Wire and Lamps

Fittings for Manifold.—

2—4 to 3 Swedge Nipples
2—3" Gate Valves
2—3 to 2 Swedge Nipples
2—2" Dart Flange Unions
6—2" Malleable Tees
6—2" C. I. Plugs
1—2" Q. O. Gate Valve

Derrick Tools.—

1—Pair No. 16 Vulcan Tongs
2—Pair No. 15 Vulcan Tongs
2—Pair No. 14 Vulcan Tongs
2—Pair No. 13 Vulcan Tongs
2—Ball Pein Hammers
1—Derrick Hatchet
1—25' Derrick Hose
1—36" Stilson Wrench
2—24" Stilson Wrenches
1—18" Stilson Wrench
1—14" Stilson Wrench
6—Wire Rope Clamps
1—21" Monkey Wrench
1—15" Monkey Wrench
1—8" Monkey Wrench
1—10" Snatch Block
1—250' Cat Line
1—50' Jerk Line
1—7-Point Hand Saw
1—6' Cross-Cut Saw with Handles
1—Carpenter's Adz with Handle
1—2' Square
1—Spirit Level
1—12" Hack Saw
12—Hack Saw Blades
1—Single Bit Axe with Handle
1—½" Erwin Solid Center Ship Auger
1—⅝" Erwin Solid Center Ship Auger
1—¾" Erwin Solid Center Ship Auger
1—⅞" Erwin Solid Center Ship Auger
1—1" Erwin Solid Center Ship Auger
1—Handle
1—Long Snout Engineer's Oiler (Brass)
1—Squirt Can

Blacksmith Tools.—

1—250-lb. Anvil
2—14-lb. Sledges with Handles
1—Flatter
1—Fuller
1—Hot Cutter
1—Cold Cutter
1—No. 3 Star Blower
1—Combination Vise

Boiler Fittings.—

1—1¼" Penberthy Injector
1—1¼" Asbestos Packed Cock
1—3 to 2 Swedged Nipple
1—2" Cross Tee
1—3" Cross Tee
2—1¼" Check Valves
6—1¼"x4 Nipples
6—1¼"x6 Nipples
6—1¼" Tees
6—1¼" C. I. Plugs
6—1¼" Ells
1—Beaver Stock and Die up to 2"

Extra Fittings to Connect up Lines for Rig.—

12—2x4 Nipples
12—2x6 Nipples
12—2" Stop Cocks
12—2" Globe Valves
12—2" Ells
12—2" Tees
12—2" C. I. Plugs
12—1" Globe Valves
12—1" Ells
12—1" Tees
12—1" C. I. Plugs
12—1x4 Nipples
12—1x6 Nipples

Bits, Drill Collars and Bushings.—

3—14" Bits
4—9⅞" Bits
6—8½" Bits
4—5⅞" Bits
1—6" to 4"x18" Drill Collar
1—4"x4"x24" Drill Collar
1—3"x4"x24" Drill Collar
1—6"x4" Steel Bushing
1—10"x6" Hyd. Swedge Nipple
1—6"x4" Hyd. Swedge Nipple
1—4"x3" Hyd. Swedge Nipple
1—Set 10" Fairs Regular Elevators
1—Only 6" Fairs Elevator
1—Only 4" Fairs Elevator
1—Pair 10" Slide Tongs
40—4" Tool Joints
1000—Feet 2" Line Pipe

Number of men needed.—It is customary to use day and night shifts in drilling with the rotary system, each shift consisting of a driller, derrick man, fireman and two helpers, and in addition to these, one tool dresser who looks after the tools of both shifts.

The day driller has charge of the entire drilling crew, and the prevailing rate of pay is as follows (1920): Driller, $10 per day; fireman, $5.25; derrick man, $5; helpers, $4.75; tool dresser, $5.50 for one well, or $8 for two wells.

As a rule, the company takes care of the men, charging them $1.25 per day for bed and meals, the estimated cost of which is from $2 to $2.25.

Fuel used.—Whenever obtainable, gas or fuel oil is used for fuel, gas costing at the rate of $12.50 a day, and fuel oil from $15 to $25 at the present prices. An extra charge of 20 cents per barrel for oil is usually added to the price paid by the pipe line companies at the well, the owner of the well laying the line for the gas or oil, or paying the hauling charges if it is carried in tank cars. From 60 to 75 days is considered a fair allowance for time in which to complete a well in this territory.

Electrification of a Rotary Drilling Rig[1].

An excellent opportunity was afforded the Gulf Production Company at Goose Creek, Texas, to drill a well, using electrical power, due to that field having been recently electrified. The application proved highly successful and the description below may prove interesting.

Description of equipment.—The equipment comprised the usual equipment for a rotary rig, only that the motors were substituted for the steam engine as the means of power. The motors used were four Type O. M. T. 15/30 h. p., 600/1200 r. p. m., 440 volt, 3 phase, 60 cycle, General Electric motors. Two motors were operated in parallel on one standard oil well motor controller and were for the drilling proper. The features of this parallel operation are as follows: The stator windings were connected in parallel, the rotor windings were likewise connected. The two grid sectors were also connected in parallel and single copper conductors were run from grid resistors to controller and collector rings, thereby eliminating any uneven currents to the rotor by reason of unlike resistances of any given resistance action. The pump motors were run independently of each other, that is, each motor was controlled by a standard oil-well motor controller. One of these motors was connected to source from the transformer bank at well, while the other motor was connected to an independent 440 volt source. This was done in order to have one pump available at all times.

Mounting of motors.—The two parallel operated motors were mounted on an extension to the universal mounting of a standard 35 H. P. Ajax engine. Both motors were belted to the same countershaft, and from the countershaft to the lineshaft on the

[1]From Oil Trade Journal, April. 1921

draw works a chain drive was provided. The pump motors were geared to the pumps. This was done by providing a special base and mounting them on top of pumps. The motors were operated in low speed with controller in the high position. However, if the pump lost its prime the motor was run in high with controller part open, and it was found the pump would pick up its prime immediately.

The transformer bank consisted of three 37.5 K. V. A. General Electric transformers banked double-delta. These transformers were at first fused for 50 amperes, but it was later found necessary to use 75 ampere fuses.

Old hole deepened.—The well, which was drilled by means of electric power, was an old hole, nevertheless a severe test on all this equipment was experienced, due to the amount of pipe milling that was necesssary to complete the well. A whipstock was dropped in the 8-inch casing. The milling was started at 2100 feet and was finished at 2109 feet, and from this depth on a new hole was made. The depth of well when completed was 2685 feet. The drilling was through gumbo, sand and boulders. The variation of speed and great amount of power necessary to do the milling was easily obtained from the parallel operated motors.

The work started December 17, 1920, and was finished January 7, 1921. The total K. W. H. consumed were 14,270, while average K. V. A. demand on drilling rig was 34. The maximum demand for 3 minute interval was 150 K. W., for 15 minute interval, 100 K. W. The serge amperes was 150 amperes at 440 volts, due to reversing of motors. The average volts were 440 and average amperes 45, while power factor of line was 0.56.

The results derived from the application of electricity to drilling were highly satisfactory.

Bits for Drilling in Rock—Rotary System

The ordinary fishtail bit commonly used in rotary drilling works very satisfactorily in soft formations, but when rock is encountered the drilling progress is slow. To overcome this difficulty numerous bits for drilling in rock have been designed. The bits which do this work successfully can be classified under two headings, namely: cross roller bits and cone bits. The cone bit drills rock by the attrition or crushing effect of two revolving cones set in the bottom

of the bit. (See Fig. 7.) The cutting action of this bit is described in great detail by Mr. H. W. Fletcher in the succeeding pages.

Fig. 7—Hughes Simplex Reaming Cone Bit

The cross roller type of bit (Fig. 8) has its cutting rollers arranged as on a cylindrical surface, the axis of this cylinder being horizontal. As the rotary drill stem revolves the cylinder revolves about the center of this axis and at the same time a rolling action is set up which puts the cutting teeth to work. It is therefore apparent that the cutting action of this type of bit is very complex, being partly a crushing action and partly a scraping action due to the drag caused by the unequal speed of rotation of the component parts of the cylinder. The manufacturers of this type of bit claim that this complex cutting action is to be desired and that good results can be obtained by using it. Both types of bits are used extensively in all fields where the rotary system of drilling is in operation.

Rotary Rock Bits—Cone Type

By HAROLD W. FLETCHER

When needed.—When hard rock is encountered in any appreciable amounts, wells cannot be put down economically by the rotary process with the ordinary fishtail bit. While the fishtail bits themselves are comparatively inexpensive, they are decidedly inefficient rock cutting tools, and considering the cost of operating a rig ($100-$150 a day) and the increased wear and tear on pipe and consequent danger of a twist-off, the cost per foot of hole is in practically all cases prohibitive.

The rotary process could not be said to be a complete success for oil well use until the development of the Hughes cone bit and later the reaming cone bit made it possible for the rotary operator to penetrate the hardest rock strata with good speed and at a comparatively low cost per foot. In many rotary fields formations are encountered where not over six inches a day can be made with a

fishtail bit, but where the Hughes cone bit will make five to six feet an hour.

Directions for use of bits.—There is naturally some difference of opinion among drillers as to the best way to run a cone bit to secure maximum results, but there are certain basic principles which govern the operation of this tool on which most operators agree, and it has been demonstrated that careful attention to these principles will be well repaid by increased speed of drilling and greater footage per set of cutters.

Fig. 8—Cross Roller Type Bit.

Weight necessary.—In the first place, for the bit to really cut, sufficient weight of pipe must be allowed to rest on the bit to cause the teeth of the cutters to actually penetrate the rock surface. This weight on a hard dolomite should be approximately 1500 pounds per inch diameter of hole; that is, a 5⅞-inch bit should carry the weight of 9000 pounds of pipe, or a 9⅞-inch bit 15,000 pounds, etc. (See Fig. 11.)

Speed of pumps.—With the weight of the bit properly proportioned to the hardness of the rock, the bit will cut away flakes of rock up to ¼ to ⅜ inch wide, ¾ to an inch long, and 1/16 of an inch thick. Obviously if drilling is to be continued satisfactorily, these cuttings must be carried up away from the bottom of the hole and not be allowed to accumulate under the cones and around the bit head. These rock chips are heavy, and tend to sink to the bottom of the hole, and a good flow of mud is required to carry them up to the surface. For a 9⅞-inch bit drilling at the rate of 10 feet

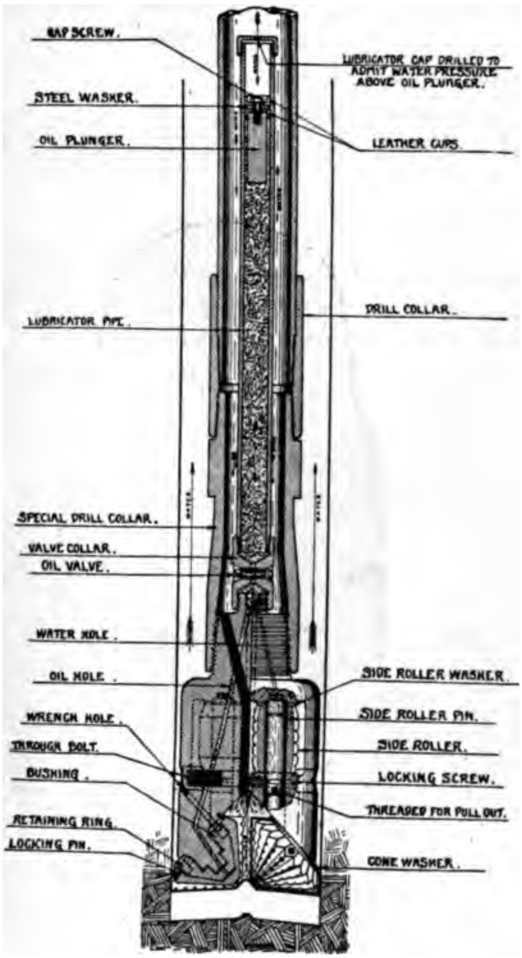


Fig. 9.—Diagram showing working parts of Hughes Reaming Cone Bit.

per hour, at least 120 gallons of mud should be pumped through the pipe per minute, and other sizes in proportion. A cone bit should always run free in any rock formation, so that the pipe can be readily turned by hand with a small pair of chain tongs. If for any reason it drags, it is usually due to cuttings collecting around the bit head and making it bind, or to a cone having stuck due to being overloaded or improperly assembled. It will usually be found desirable to lift the bit off bottom two feet every 15 minutes and let it down slowly, thereby flushing back the cuttings from the bottom of the hole and giving the cutters a clean rock surface to work on.

Advantages of proper weight.—If the cone bit is run on rock with too light a weight, there will be several effects readily recognized, particularly if the rock contains grains of quartz sand or other hard, sharp grit. In the first place, the points of the cones will be worn "cup shaped," and in fact may even in extreme cases be worn completely through. This is due to the formation of a small tit in the center of the hole which bears against the points of the cones and grinds away the metal. With greater weight the

shock of the teeth striking the base of this tit splits it away and entirely prevents this wear. Again, it will be found that with light weight the cone teeth will wear flat on the cutting edges as if they had been ground away on an emery wheel, while if the weight is sufficient to cause penetration they tend to remain more or less sharp, due to the fact that there are a large number of ridges in the bottom of the hole which get between the teeth like meshing gears and grind the sides of the teeth because of the varying pitch, thereby maintaining sharp edges. Another effect of light weight is to wear the gauge surfaces of the cones, causing them to round over and lose gauge. If the bit has enough weight on it to enable the cone teeth to split the rock particles away instead of grinding, a hole will be made slightly larger than the diameter of the bit, and there will be consequently no "pinching" of the cones and loss of gauge will be greatly reduced. Proper weight is the principal factor governing the satisfactory operation of these rock drills. Exami-

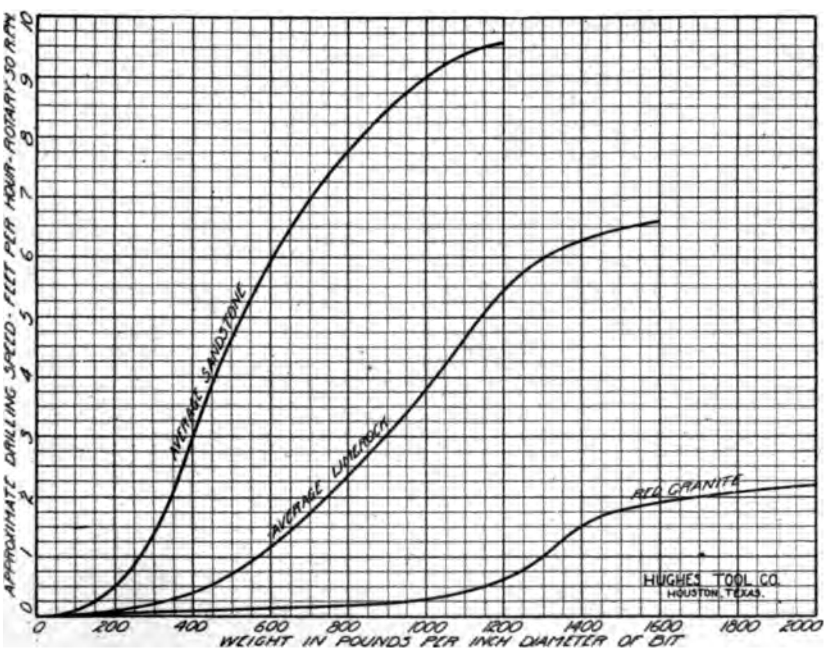


Fig. 10—Approximate drilling speed of Hughes Cone Bits in various formations.

nation of the returns will give some idea of whether or not the weight used is sufficient as, even in deep holes, rock chips of appreciable size should come back in the mud, though sometimes it will be found that failure to find these particles is due to insufficient flow of fluid which allows the cuttings to remain at the bottom of the hole until the cones have ground them into powder.

Speed of rotation.—Speed of rotation is a matter to be determined by local conditions. In a hard rock which has no tendency to stick to the cones, 40 to 50 revolutions per minute will give the best results. In a sticky rock, 65 to 75 revolutions per minute will give the best results, as the teeth on the cutters will not penetrate so deeply, and the cuttings will be thrown clear of the cones, and will wash back in the returns.

The cone bit will drill small streaks of gumbo if run at a high speed, 75-80 revolutions per minute, and fed down very slowly,

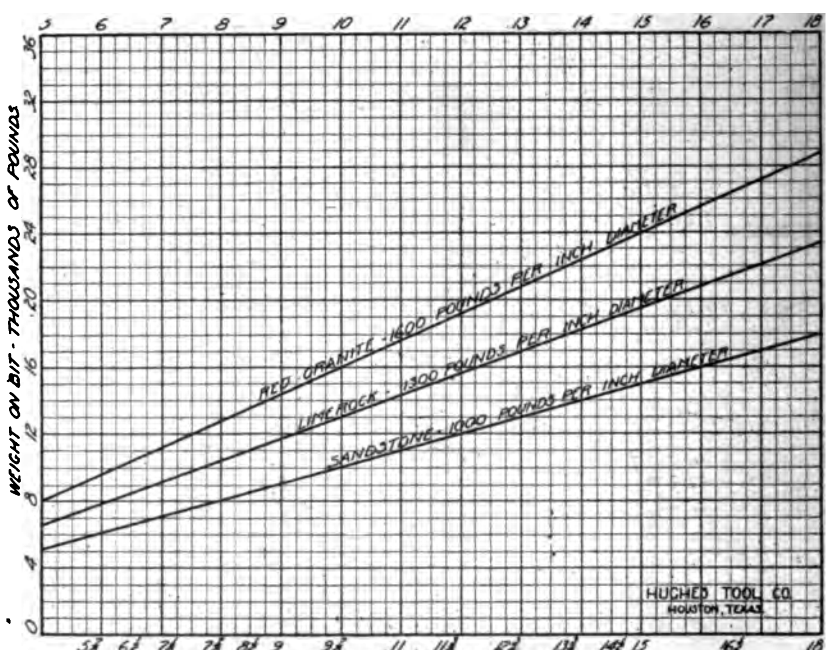


Fig. 11—Drilling weight recommended for Hughes Cone Bits in various formations.

say two or three feet per hour, with plenty of flushing water, and the bit can therefore be used to advantage in "broken" formations.

Some exceptional records have been made with the cone bits, drilling speeds of 15-18 feet per hour having been reached in a number of cases, and 300 to 500 feet of hole made with one set of cutters. On an average, however, a good driller can expect about five feet of hole per hour and from one hundred to two hundred feet of hole per set of cutters, in the average rock encountered in the Mid-Continent and Coastal oil fields. (See Fig. 10.)

The Pickin gyrating rock drill.—Where unusually hard formations are encountered at considerable depth in a small diametered hole, the Pickin bit is very serviceable, because, having a single cutter almost horizontally placed, it will drill under great weight. Because of its gyrating movement the bit drills a slightly larger hole than its own diameter, giving ample clearance space.

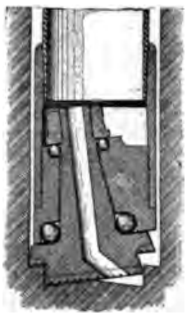


Fig. 12—The Pickin Bit.

Disc bits for drilling in soft formations.—The Hughes patent disc bit with solid head and inclined cutters is shown in Fig. 13. This bit has thirteen times as much cutting edge as the fishtail bit, and with the cutters constantly revolving it combines a cutting and crushing action. It is claimed by the manufacturers that this bit will drill faster and last longer than the ordinary fishtail bit. It has been most successful in drilling sandy shales, soft sandstones and clays which are fairly well indurated. The disc bit works much better in these formations than in soft, plastic gumbos or similar formations.

This type of bit was used quite extensively in the Burkburnett oil field of North Texas during the 1918 drilling campaign and some very good records were made with it. Several contractors reported being able to make as much hole as

Fig. 13—The Disc Bit.

300 feet per day with it under favorable circumstances. They used it in shales, clays, sands and intervening thin strata of rock. The disc bit has also been successfully used in Wyoming and the western fields.

Fig. 14-a—Hughes Tool Joint.

Rotary Tool Joints

Tool joints are tapered joints inserted in the drill stem in place of ordinary couplings or collars, and they usually occur every third or fourth joint, depending on the height of the derrick. They consist of a standard box and pin, each of which is threaded on the other end to receive the regularly threaded drill stem. The taper or size of the box and pin has varied according to the individual whim of the various manufacturers, but there has been a very concerted effort of late to get all manufacturers of tool joints to adopt a standard thread. Most manufacturers are now using a 3¼x4¼ box and pin threaded five threads per inch on their 4-inch tool joints. Of late the tendency has been to make the threads coarser as a more careful study is made of the use to which the tool joints are put on the derrick floor. One company has adopted the Acme or flat thread for all tool joints after making a careful study of the matter. (See Fig. 14a.

Fig. 14-b—Mack Tool Joint.

Rotary tool joint threads are never wiped clean and polished before being made up as are tool joints used in the cable tool fields. On the other hand they are "doped" with a very heavy oil or grease, included in which is usually a generous amount of mud and sand, and screwed together. In setting a "fourble" with a pin on the bottom upon the box into which it is to be screwed the drillers are none too gentle, and if the threads are fine the tops of the threads are usually knocked off. The fit between the threads of the finely threaded box and pin is very close, and

the mud, sand and pieces of steel collecting in this space tend to "freeze" the joint. When unscrewed after becoming stuck in this manner, the threads are usually stripped off. Hence the tendency to get coarser and coarser threads with more clearance between them.

TABLE SHOWING DIMENSIONS OF STANDARD TOOL JOINTS

Size	Length	Outside Diameter Inches		Size Box and Pin Inches		Weight
Inches	Inches	Eastern	Western	Eastern	Western	Pounds
2½	15	3¼	3 15/16	1¼x2¾–7	2 x3 –7	36
3	15	4⅛	4⅛	2¼x3¼–7	2¼x3¼–7	44
4	18	5⅜	5¼	3 x4 –7	3½x4½–7	78
4	18	5½	...	3¼x4¼–6	....	78
4	20	5⅛	5¼	3 x4 –7	3½x4½–7	87
6	18					130
6	19					139
6	20					149
6	21					158
6	22					167
6	23	7¼		5x6–4	5x6–4	176
6	24	or	7¼	or	or	186
6	25	7½		5x6–7	5x6–7	196
6	26					205
6	27					215
6	28					224
6	29					233
6	30					243
6	31 to 36					...

Figure 14 gives characteristic views of the ordinary tool joint.

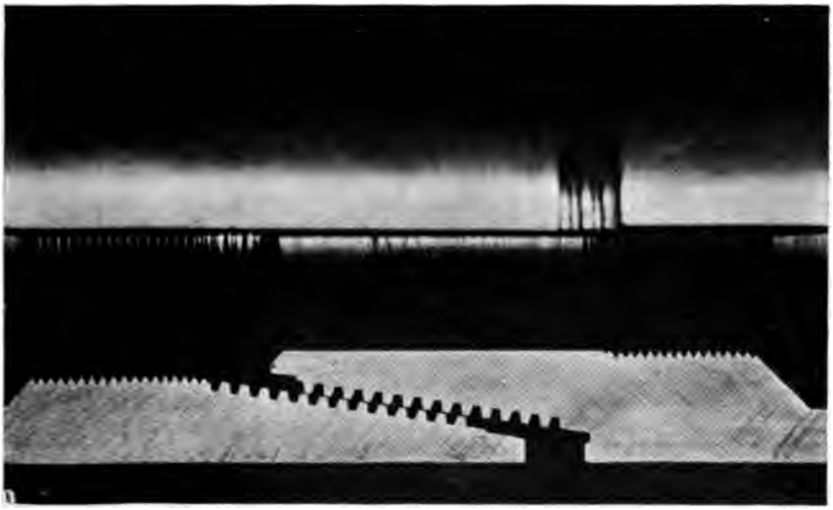


Fig. 14-c—Illustration of flat thread used in Hughes Tool Joint.

Fishing Jobs—Rotary Drilled Wells

In the course of the drilling of a well with rotary equipment, fishing jobs are encountered but they are commonly of a comparatively simple character compared with those encountered in the cable tool system of drilling. Almost all of the tools used in rotary fishing are run on pipe and all pulling is done on the pipe on which the fishing tool is run. Therefore rotary fishing jobs are primarily pipe fishing jobs.

Tap Overshot
Fig. 15—Rotary Fishing Tools

The most common form of fishing job is caused by the twisting off of the drilling pipe. The lost pipe can be recovered by running an "overshot" (See Fig. 15) which consists of a bowl made up so as to be large enough to go over the drill pipe collar or tool joint. It contains slips on the inside which catch under the collar or tool joint when the fishing pipe is pulled up. A newer type of overshot is so made that if the lost drill pipe will not come after catching hold of it, the slips can be released by rotating.

Fig. 16—Bull-dog Wash-Down Spear.

If it is not convenient to run the overshot, a bull-dog wash-down spear is run. (See Fig. 16.) This fishing tool has the advantage that it can be worked down through a hole that is badly caved. Care should be taken to see that the slips used in this spear are the proper size for the weight of pipe for which you are fishing. As the slips are made to close size, a very small variation in the internal diameter of the lost pipe will cause the slips to not take hold or be unable to enter the pipe. It is always well to have all of these facts at hand before ordering a spear from a supply house. After catching hold with a spear of this type a good strong pull is taken. If the lost pipe refuses to come, the spear can sometimes be recovered by rotating. Also if the lost pipe contains tool joints and the fishing string has been tightly made up, some

of the lost pipe can be recovered by "backing up" and unscrewing the pipe at one of the tool joints.

One common method of recovering drill pipe which will not pull is by fishing with a string of pipe threaded with left-hand instead of right-hand threads. A good hold is taken with a spear or left-hand threaded pipe tap and then the fishing string is "backed up" or rotated in the common direction for unscrewing. This tightens the left-hand threaded pipe joints and unscrews those below. Three or four joints of pipe are commonly recovered with each run.

Fishing with die nipples as described on page 110 is also commonly practiced in rotary country. Also left-hand threaded and right-hand threaded taps are used. These can be threaded into pipe or tool joints and will stand a very severe pull.

If the lost pipe cannot be recovered, a whip stock is dropped into the hole and the fishing job is "sidetracked." Very little trouble is occasioned in "drilling by" lost pipe with rotary tools. If it is desired to sidetrack and the lost pipe happens to be inside the casing, a milling tool is run immediately after the whip stock is dropped and a hole is milled in the casing through which drilling can proceed. The ease with which work of this kind can be done and drilling work be continued to great depths beyond the point where the pipe is sidetracked is easily understood when it is borne in mind that it is not necessary that rotary drilled holes be as straight as those drilled by the cable tool system.

TABLE SHOWING DIMENSIONS OF OVERSHOTS

Size Pipe to Run on, Inches	Size Pipe to Run in, Inches	Size Pipe to Catch, Inches	Weight, Pounds
6	8¼	4	100
6	10	4	260
8¼	10	4	236
8¼	10	6	198
8¼	12½	6	310
10	12½	6	312

Device for preventing twist-off fishing jobs.—J. D. Baughner, a driller employed by the Union Oil Company of California, has invented a device for preventing fishing jobs caused by twist-offs

in the rotary system of drilling. This device is being used quite extensively in the fields of Southern California.

Rotary drill stems are made up of special pipe and the majority of fishing jobs encountered in drilling a rotary hole are caused by the twisting off of this stem at the joints, or couplings. Twist-offs will ordinarily occur at one of the couplings between the tool joints. It is also a fact that most twist-offs occur near the bottom of the stem, since the greatest stress is developed at that point. Mr. Baugher's device is therefore applied to the bottom 80 feet of the drill stem, or between the lowermost tool joint and the drill collar.

The essential purpose of the device is to tie the four bottom joints, drill collar, and bit, to the nearest tool joint. This is effected by the use of a wire cable babbitted into a wire line socket at both ends. The wire line sockets are shouldered and rest on the pin of the drill collar. Between this shoulder and the top of the pin a heavy slotted washer is placed, and it is equipped with holes to allow the water free circulation. The slotted washer holds the enlarged end of the rope socket at both ends of the drill pipe. The cable in the pipe rotates with the stem and in no way hinders the action of the water or circulating mud.

Fig. 17—The Baughner Device for Recovering Twist-Offs.

Should the drill collar and bit twist off while drilling in a very broken formation, the wire line connecting it with the tool joint prevents it from becoming entirely disconnected from the drill stem and upon pulling the drill stem from the hole the twisted-off portion will be recovered and a very difficult fishing job avoided. On one well in California this device prevented 24 out of 27 fishing jobs of this nature.

Mud-Mixing Methods.

It is very necessary in a rotary-drilled well to have a good thick mud for plastering the walls of the hole when drilling through sands or caving formations. In almost every hole drilled in wildcat territory some time has to be spent in mixing mud. There are various methods of doing this. They are enumerated as follows:

1. **Using a regular mud mixer** such as is sold by the oilwell supply companies. These are placed near the drilling engine and have a sprocket on them that fits No. 103 chain. The regular rotary drilling chain is simply extended backwards from the sprocket on

Fig. 19—Vertical Mud Mixer

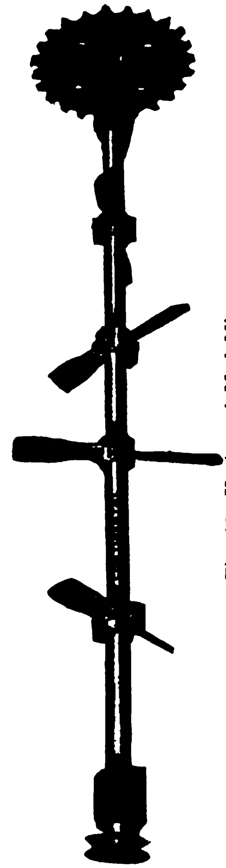


Fig. 18—Horizontal Mud Mixer

the line shaft to operate the mixer. The mixing shaft in the mixing box is usually vertical with a bevel geared arrangement at the top to horizontal shaft on which gear is connected. Some mixers, however, have a horizontal mixing shaft and use no bevel gear. The mixing shaft is equipped with paddles which do the mixing.

2. **A home-made mixer** can be rigged up easily if one has an old sprocket with teeth with proper pitch for No. 103 chain. A piece of 4-inch pipe about 7 feet long is perforated with 1¼-inch

holes for about 3½ feet on one end. Six or 8 holes are drilled straight through. Pieces of 1-inch pipe 2½ to 3 feet long are inserted in these holes for paddles and flattened near the 4-inch so that they are held rigid in the 4-inch. The sprocket is shrunk on the other end of the 4-inch pipe and the mud-mixing shaft is ready. A good strong box is then built out of 2-inch lumber and made large enough to clear the paddles. Pieces of 4 by 4-inch lumber are nailed across the ends of the box and sawed out to fit the shape of the cross section of the 4-inch pipe. These act as bearings or pillow blocks. The box is boarded up 2 to 3 feet above the 4-foot shaft to catch the flying pieces of mud. It is set in the derrick floor in front of the rotary or on the ground near the drilling engine with the mixer sprocket lined up with the rotary sprocket on line shaft of the draw works.

3. **Mixing with steam.**—In this method an auxiliary pit is dug near the main slush pit or a strong box is built alongside the mud ditch. One constructed at Stratton Ridge, Texas, was 5 by 5 feet in cross section and 16 feet long with a sliding door in one end 1 foot above bottom of box. After the box has been half filled with clay and water the steam is turned on. Steam pipes made of 1-inch or smaller pipe are usually installed in the corners of the boxes. They point towards the center of the box so as to keep the mud in motion as much as possible. This method of mixing mud is somewhat slower than that employing the mechanical mixers above mentioned but it gives very satisfactory results.

4. Mud could be mixed by simply shovelling clay into the hole and drilling through it. Care must be exercised, however, as the clay tends to plug the bits and causes very uneven drilling.

5. It is reported that at White Point, in the Texas Gulf Coast region, when the Gulf Production Company wanted thicker and heavier mud they mixed large quantities of neat cement with regular drill mud. This gave a mud of great weight, aiding in preventing blowouts and made an excellent plaster.

In selecting clay, from which to make mud, great care should be exercised. Very few clays will make good mud. A clay must be very plastic and almost absolutely free from sand to make a good drill mud. A sample of the clay mixed by hand in an ordinary wash basin will usually show what kind of drill mud it will make.

The Sampling of Rotary Drilled Wells.

General Consideration.—Much better work can be done in the collecting of accurate samples from rotary drilled wells than is apparent at first thought. The writer has heard some very severe criticism of the rotary system of drilling on the ground, that it is impossible to get accurate samples of the formations drilled through. This is not so however for it is possible to get very accurte samples of rotary drilled wells, providing proper precautions are taken.

The first rule to lay down in considering the subject of accurate formation records in rotary drilled holes is to admit that the driller on the well is a man of average intelligence, who knows from the way his rotary is working the general character of the formation he is drilling in; that is, whether it is hard or soft, gummy or otherwise, whether it cuts clean or is full of "boulders." This is told partly by the way the pumps work and partly by the ease with which the formation drills.

Then we will assume that a couple of joints of surface casing have been set with a tee at the top into which a joint of 6-inch pipe has been screwed for conducting the drill mud to the side of the derrick. The sample can be collected in a sawed-off nail keg into which three or four thread protecters have been placed. This keg is placed under the discharging fluid so as to intercept a part of the column. As a general rule the thicker the drill mud the more accurate will be the sample obtained. This is due to the fact that thick mud plasters the hole and keeps it from caving and at the same time it forms a coating around unconsolidated material and carries it to the surface in its natural state. The writer has seen small balls of unconsolidated oil sand up to ¼-inch in diameter which came from 2000 feet underground. This material when picked from the sample keg looked like a small ball of clay, but upon being broken open it proved to be a ball of very fine grained oil sand plastered with mud and still containing the "live" oil which it carried when drilled into.

Length of time to wait for sample.—Next we will assume that the drill has been working in a stiff gumbo as shown by the way

cuttings behind the current of drill mud. It is quite possible that these two factors can be left out of this consideration as they are small and tend to offset each other. Of course the lag of the cuttings will be less the heavier the drill mud used and the faster the pumps are run.

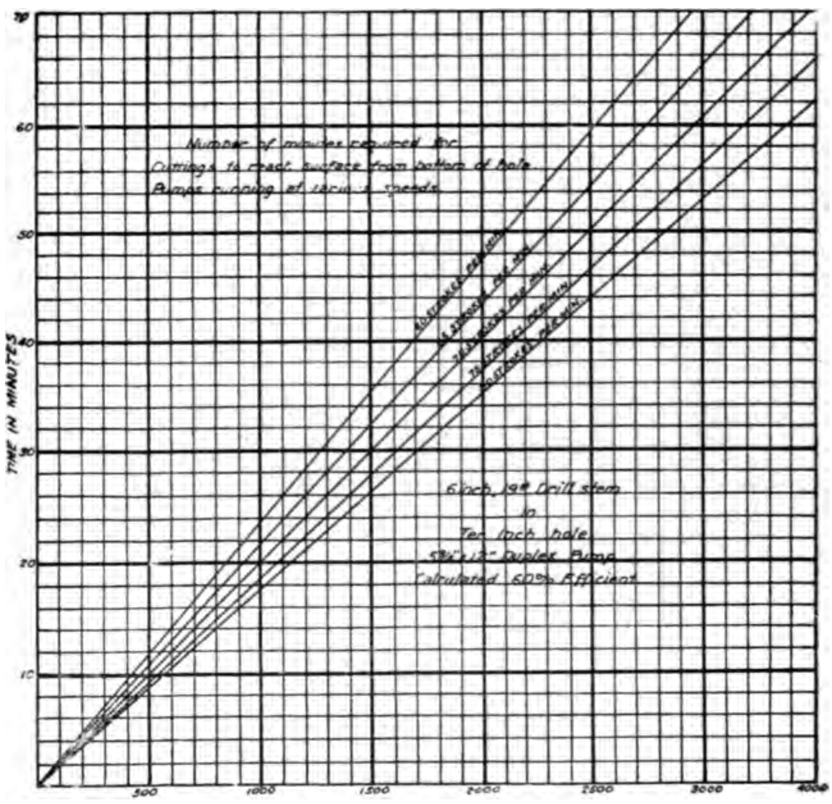


Fig. 22—Graph showing length of time to wait for sample 6-inch drill stem in 10-inch hole.

Marking of grief stems.—Most all of the grief stems or "Kelly Joints," in use by the better class of drillers in the Gulf Coast country are marked with a cold chisel every foot of their length. These stems are further marked in roman numerals beginning with one at the bottom and going to 28 at the top. The driller keeps track of the depth to the change in the formations by noting the mark on his grief stem at the time he enters the new formation. As he

has a correct tally of the amount of drill stem in the hole at all times this gives a very accurate measure on the top of the new formation. By making the same notation when he goes out of the new formation, he knows exactly the thickness of the formation and the point at which it occurs. By waiting the proper length of time to collect the sample from the sample box he will then have an accurate sample of the formation as well as a correct notation as to its depth below the surface and its thickness.

It has been the writer's experience in cable tool country that no such accurate information as to the depth of the formation is at hand. It is customary to run a steel measuring line in the North Texas cable tool district, only every week or so, or when getting ready to set casing or probably when entering a formation like the black lime. In the meantime the drillers keep track of the depth to the formation on the sand line. The writer has checked up many holes with a measuring line which were as much as 40 to 50 feet off. In this respect the rotary country gives much greater accuracy than the cable tool country.

Getting the sample.—After the pumps have run the proper length of time to bring the sample to the derrick floor the sample keg is inserted under the edge of the column of drilling mud coming from the 6-inch casing. After a lapse of several minutes this keg is removed and another inserted in its place. The cuttings in the keg are then washed with clear water in order to free them of drilling mud. This sample while still wet is inspected by the driller and then poured into a bottle for future reference. It is very desirable to leave the sample wet because in this manner it stays in its natural state and can be inspected weeks later for oil, etc., and still have any light oil which might be held in the sand.

In the meantime any indications of gas will be noted in the frothy nature of the drill mud as it comes from the well and circulates in the ditch. Several samples are usually taken in the keg and each one checked against the others in order to arrive at the exact nature of the formation drilled through. Some pieces of overlying formations which have caved off in the hole will naturally be found in with the cuttings from the bottom of the hole but these will not be considered as the driller will recognize them having seen them previously. In drilling with cable tools where much open hole is carried this same trouble arises and but little more

discretion is necessary in selecting samples from rotary drilled wells than from cable tool drilled holes.

When pulling out to change bits there will usually be a very good sample of the formation last drilled through clinging to the sides of the bit. This gives a very accurate sample from a particular point but is not satisfactory as a sample of the whole formation as the one which is gathered from the sample keg.

The sampler.—Companies drilling wildcat tests usually keep a sampler on the rig at all times and it is this man's business to bottle the samples furnished him by the driller. In this way the driller is relieved of all the trouble of collecting samples and can devote all his time to making hole and looking after the machinery. Usually the more competent a driller is the more interested he will be in making hole and the less time he will want to spend in collecting and preserving samples. It has been the writer's experience that the better class of drillers are very glad to have a sampler on the derrick floor and if the sampler is the right kind of man he can be made very useful. Some companies give the sampler other duties to perform such as keeping time, making out fuel oil reports and helping the driller with his drilling reports.

Many of the larger companies operating in the Gulf Coast country require only dried samples to be sent to their main office for inspection. These samples are tabulated, analyzed and filed away in the geological department. The samples from each well are kept in separate compartments of the filing system in consecutive order from top to bottom. A detailed log is prepared in the geological department from these samples and this is checked against the log sent in by the driller upon the completion of the well. Different filing systems are used by different companies but they all answer the same purpose.

TAKING OF CORES.

Coring soft formations.—At various times it is desirable to take cores of formations in rotary drilled wells and there are several successful methods in use for doing this. Some companies have been using a coring device in soft formations in which the core barrel is incorporated in the center of a fish tail bit or in other words the fish tail bit is so made as to have a hollow tube of about 1½-inch diameter running up the center. This 1½-inch opening

in the shank of the bit is threaded and pipe is screwed into it of sufficient length to take the amount of core desired. The opening up the center of the bit is tapered somewhat and this makes it slightly larger at the top than it is at the bottom. This tapering effect is made for the purpose of catching the core and holding same when the drill pipe is pulled from the hole.

Using this device a hole is maintained of standard gauge and the drilling is performed in the same manner as if they were using an ordinary fish tail bit. The only objections are that the sample as obtained is not kept in its original state and the length of sample in the core barrel does not give the thickness of the formation drilled into.

The core barrel shown in the attached drawing (Fig. 23), probably has a broader use than any other. It is made by cutting off and bending over the bottom of a piece of pipe and it cuts like an ordinary post hole auger. In pulling out of the hole the lip holds the sample in the barrel. The Gulf Production Company uses this device in preference to all others.

The Holland core barrel.—Dr. W. A. J. M. van Waterschoot van der Gracht, President of the Roxana Petroleum Corporation invented a coring device for taking cores in soft formations when drilling with the rotary system. He used this very satisfactorily and very successfully while prospecting for coal deposits in Northern Holland at the time he was Director of the Geological Survey of the Netherlands. It is understood that this core barrel has been used by the Shell Company of California. They are made by the Holland Drill Company of the Netherlands.

The only complicated thing about this coring device is the shoe which is screwed onto the 6-inch drill stem. The core barrel can be 4-inch in size and of a sufficient length to take the amount of core desired. There is no reason why a 30-foot core can not be taken at one time if it is wanted. The core barrel is made up of 1-foot lengths of flush joint pipe and the bottom one of these is screwed into the shoe. The shoe is made of steel and has water courses running through it. The bottom of this shoe has slots into which fit cast steel cutting teeth. These teeth are set into the shoe in somewhat the same way as removable teeth are fitted into circular saws in saw mills. As fast as the teeth are worn out they are taken from the shoe and new ones inserted.

Hence there is never any blacksmithing to be done when using this core barrel. On the inside of the shoe, some small springs are attached which keep the core from falling out, once it is taken. On

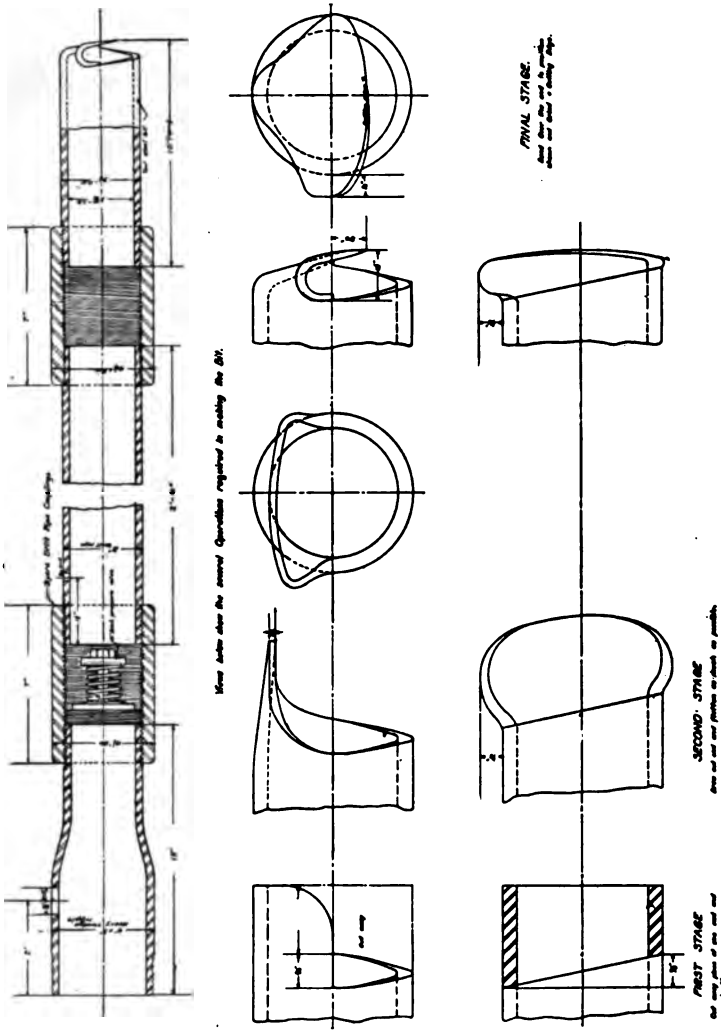


Fig. 23—Core Barrel for Taking Samples of Soft Formations—Rotary Drilled Wells

the top of the core barrel an ordinary back pressure valve is fitted. This allows the mud and water contained in the barrel to be forced out as the core moves up the barrel and prevents the drill mud from entering the top of the core barrel.

When the core is removed from the hole some difficulty will always be found in getting it out of the core barrel. In using 1-foot lengths of flush joint pipe these can be unscrewed and the core pushed out in 1-foot lengths.

Another type of core barrel.—In Fig. 24 is shown a drawing of a coring device used by the Rio Bravo Oil Company for coring in soft formations. This has performed very satisfactorily but it has the objection that only 4 or 5 feet of core can be made

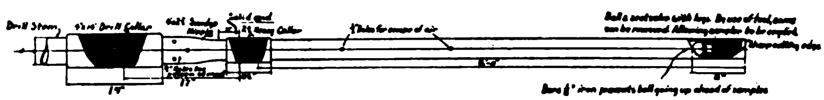


Fig. 24—Core Barrel Used By Rio Bravo Oil Company.

at one time, and all hole made has to be reamed to size afterwards. This reduction of hole is sometimes quite desirable in looking for casing seats and in feeling ahead for oil sand when it is desired to set a string of casing immediately above the oil sand.

Coring Rock Formations.—For coring rock in the Gulf Coast country there are many successful types of coring devices in use. One of the most common is an ordinary piece of pipe which has been annealed and had teeth cut on the bottom of it. It is referred to as a "basket" by the drillers. The pipe is lowered into the hole and rotated for the length of core which it is desired to take and then the drill pipe is lifted up a short ways and dropped until the driller feels reasonably sure that the teeth have been turned in enough to hold the core while he is pulling out of the hole. This device very seldom fails to catch the core.

Mr. A. R. Gamble, driller for the Humble Oil Company at Stratton Ridge, in Brazoria County, has probably taken as many cores as any other driller in the Gulf Coast country. He uses an ordinary piece of pipe on the bottom of which a small v-shape notch is cut. This is lowered into the hole and rotated on bottom. It has been found that this core barrel makes a core just as fast as any other style in use. The barrel is rotated until the amount of hole desired has been made. (Cores 8 to 10 feet long are commonly taken.) The swivel is then unscrewed on the derrick floor and a double hand full of small pieces of cast iron of about the same size as one's finger nail is dropped into the hole. The swivel is then screwed back on and the pump started. As soon

as these pieces of cast iron have reached bottom the drill stem is raised and lowered slowly. After repeating this a few times the drill stem and core barrel are pulled out. The pieces of cast iron become lodged between the barrel and the core and hold the core in the barrel. In almost every case the core is recovered.

Of course after using either one of these types of core barrels it becomes necessary to ream the hole before drilling ahead.

Screen Casing and Its Use.

A good description of the common types of screen casing is given by Mr. Wm. Kobbe (Trans. A. I. M. E.), as follows:

"Screen casing may be divided into two general classes: (a) the screening device on the outside of the casing, see Fig. 25-A; and (b) the screen forming a part of the casing wall, see Fig. 25-B. In the first type the screen generally consists of wire wound around perforated casing, while in the second type the screen is in the form of numerous buttons or slotted brass plugs carried in the walls of the casing and flush with the outside surface. This latter type, known as 'wireless' screen, has the advantage of withstanding hard usage, and many operators have carried it for considerable distances through unconsolidated sands. The wire-wound screen casings are entirely unadapted for carrying through thick strata of unconsolidated sands and the attempt to finish a well in that way should never be made. In finish-

Description

Point 1—
Pipe recessed, wire wrapped in recess and sweated to pipe, forming a solid collar on both ends.

Point 2—
Keystone wire, accurately wound on pipe by our patented winding machine.

Point 3—
Lugs punched on wire which accurately spaces Keystone wire and keeps it spaced.

Fig. 25-A—Layne & Bowler wire-wrapped screen or strainer

ing a well with the wire screen it is necessary to set it either inside a conductor string or by means of a rotary, as otherwise the wires may become detached from the casing and cause endless complication and trouble."

In the Gulf Coast fields the wireless screen has been used very successfully in jobs where it was rotated on a string of drill pipe with a fish tail bit and carried through many feet of formation without injury to the screen. Where it is not necessary to rotate to bottom and where the hole is of ample size the wire wrapped screen works very nicely and it is used quite extensively in the Gulf Coast.

Section Showing Construction

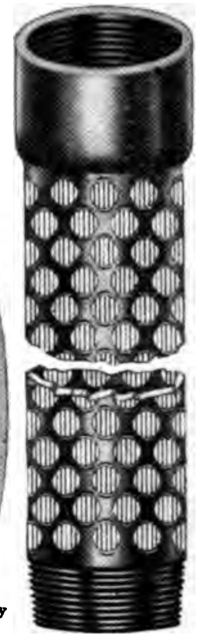


Fig. 25-B — McEvoy screen or strainer

Table Showing Comparison of Standard Screen Gauges.

Layne and Bowler	McEvoy (No.)	Getty (Mesh)	Width of Opening (Inches)
	125		
	100		
.080	80	10	.080
.038	38	20	.038
.024	24	30	.024
.015	15	40	.015
.012	12	50	.012
.010	10	60	.010
.009	9	70	.009
.008	8	80	.008
.007	7	90	.007
.006	6	100	.006
.005	5	110	.005

Setting Screen Pipe[1]

Frequently when setting screen pipe or any other type of perforated pipe in a well that has been drilled through the oil sand with mud fluid in the hole, it is necessary to wash the mud out of the well before finally setting the casing on bottom. If there is a strong gas pressure in the well it is not likely that any extra equipment will be needed for this work. The mud-laden fluid should be thinned as much as practicable, and the screen run in as rapidly

[1]E. W. Wagy in Technical Paper No. 247, U. S. Bureau of Mines.

as possible. The high gas pressure will force the mud out of the sand into the well and then help clear the well of the mud fluid.

Conditions requiring wash pipe method.—The wash pipe A, (Fig. 26) is a pipe of smaller diameter than the casing to be set, usually 3-inch or less, and extends from the surface to the packing device below the perforations, or extends between two packers—one below and one above the perforations. The purpose of using a wash pipe is to conduct the water to the lower end of the screen pipe before it issues through the perforations.

The wash pipe method of setting shop-perforated casing and screen casing is used where two separate conditions prevail—one, where there is a minimum gas pressure and it is desired to wash the hole free of mud by conducting clear water down through and around the shoe joint of the casing to be set; the other, where there is an excessive gas pressure. In order to keep the well under control and prevent a blowout with its consequent disastrous results, fluid has to be circulated at frequent intervals. However, it will often be necessary to clean the hole 20 or more feet below the pipe, and then fill the well with mud fluid again in order to overcome the gas pressure. After the gas pressure has been overcome, the next joint of casing should be put in as quickly as possible.

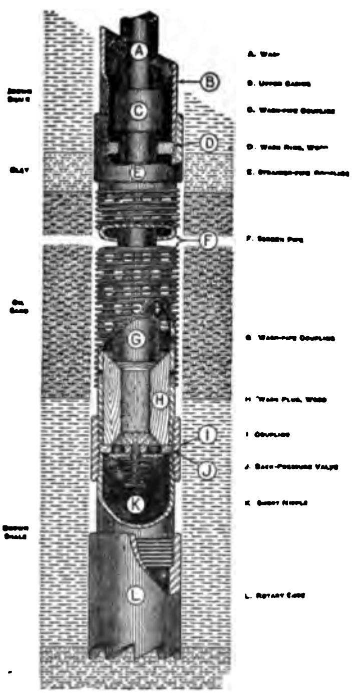


Fig. 26—Diagram showing method of setting screen pipe when mud-laden fluid has been used in drilling the well. Is particularly adaptable to wells drilled by the rotary.—From U. S. Bureau of Mines.

Equipment when using entire length of oil string.—When the gas pressure is not great enough to clear the sand around the hole of mud, or it is impractical, on account of caving, to thin the mud in the well, the following method is in general use (see Fig. 26):

To prevent "heaving sands" coming up on the inside of the casing, a back-pressure valve, J, is set below the perforations. On top of this

valve a wooden wash plug, H, is set to receive a wash pipe, A, of whatever diameter is desired, usually 2 or 3 inches. The wash pipe should have a coupling on each end (C and G). Some operators have used a packer instead of a wooden plug, with uncertain results. The sand sometimes ran in on top of the packer and made it difficult to remove. The wash pipe should extend from the bottom wash plug, H, to a foot or more above the top coupling, E, of the screen pipe. Within this top coupling a packer or wash ring, D, of some soft material should be placed around the wash pipe to prevent any fluid from going around the outside. By this means the water is carried from the pump down through the bottom of the strainer as the latter is being run into the hole. This will clear the well of sand, and when the strainer is nearly on bottom, clear water can be used to wash the walls free of any mud that may be present.

In some localities where there are shifting sands, operators have found it more profitable to let the entire length of the oil string remain in the hole. A slight strain can be placed on the casing and it can then be clamped up. This will help support the strainer in the bottom, it will not be so liable to shift over or get damaged, and, when redrilling, the chance of removing all of the oil string will be greatly increased.

Removing wash pipe.—When the outside washing is complete, a string of tubing is lowered into the well and is screwed onto the wash pipe. As the wash pipe is being withdrawn, pump pressure is placed on it to help clear the strainer of any sand that may have run inside during the setting. In fact, hydraulic pressure may be necessary to help remove the wash pipe, if sand has settled tightly around it. If the use of pumps to help loosen the wash pipe is unnecessary, the pipe may be lifted out by using a tubing spear run in on a wire line. It may be advisable to do such pulling with the calf wheels.

If the rotary method of drilling has been used, a rotary shoe (L, Fig. 26) or drill bit can be placed on the bottom of the screen to facilitate cleaning.

Recovering part of oil string.—When it is desired to recover part of the oil string used for setting the strainer, because another string of casing has previously been set on top of the oil sand, the method is slightly modified. As mentioned before, a plain casing shoe inverted and threaded with left-hand threads may

be used as an adapter. Another adapter in common use is a lead seal coupling. The top coupling, which has a left-hand thread, is fitted with a lead ring, which can be expanded by means of a swage or sealing iron tool to fit the outside casing more closely. Into the lead seal coupling is screwed a short right and left-handed thread nipple, on top of which is fitted a steel wash and pull ring. When the left-hand nipple is backed off preparatory to pulling the top casing, this steel ring catches on top coupling of the wash pipe, and is pulled out.

Canvas Adapter Packers Used in the Gulf Coast Fields

In the Gulf Coast fields lead seal adapter packers have been found very unsatisfactory owing to the fact that it is impossible to make a seal in the hole between lead and steel which will hold back water. The Layne & Bowler Company of Houston, Texas, manufacture a canvas packer which is run on the string of pipe to which the strainer is attached and it is placed in the strainer string so as to come 40 or 50 feet up the hole from the bottom of the last string of casing run (see Fig. 27.) This packer is run on a setting tool and as soon as the strainer is landed on bottom the pipe at the top of the hole is turned to the right about 31 turns which releases the ratchet threaded setting device. The weight of the pipe above the packer is then let down

Ratchet Threads. (1)—These are left-hand buttress threads and being shallow cut, do not weaken the pipe to any extent, preventing the packer from uncollapsing when exposed to high gas pressure. They can be unscrewed and thus partially release the packing if it is desired to pull the packer.

Canvas Packing. (2)—The canvas consists of eight-ounce duck, strong and durable, yet easily compressed to almost iron hardness, thus insuring a nearly perfect pack the full length of the collapsed section of 12 to 14 inches.

Cone Lead. (3)—The lead being more substantial and non-compressing than canvas and soft enough, insures a good joint on the pipe and increases the packing capacity. Being smooth, it allows the packing to slide free, thus making a longer pack which insures more contact on well casing and lessens danger of bursting pipe.

Fig. 27—Layne & Bowler Canvas Packer.

upon the packer and the canvas is compressed to a total length of 12 to 14 inches. A lead cone which is contained inside the canvas is forced with the canvas out against the casing, and this insures a good tight pack. It also removes the danger of bursting the casing. This packer makes an absolutely watertight seal which will withstand enormous water pressures. In tests made at the plant of the Layne & Bowler Company in Houston, hydraulic pressure as high as 2000 pounds per square inch have been applied behind these packers without the slightest amount of water showing up outside.

The wash pipe is run on the setting tool in this system and when the setting tool is pulled from the hole the wash pipe is removed with it, thus saving the trouble of fishing for wash pipe.

Loosening Casing. Rotary Drilled Wells.

When getting ready to abandon a rotary-drilled well in the Gulf Coast country it is very difficult to recover much of the casing which has been landed. One of the most successful methods employed for freeing casing in this country is that used by Mr. Neils Esperson, a successful practical coastal operator. The steps are about as follows:

In pulling a string of 8-inch or 10-inch casing 9 lines are strung up on a 4-shieve travelling block with ⅞-inch steel cable. With a 112-foot derrick this takes up 1100 feet of cable. A good strong pull is made and the amount of stretch of the pipe is noted. It is usually figured that the pipe will stretch 1 inch for every 100 feet that is free. For instance, if the pipe stretches 8 inches it is estimated that 800 feet is free. If it is desired to free more than this amount of pipe a small diameter hole (5⅞ inches) is drilled down along the outside of the casing to the bottom. A pull is then made and if the pipe does not come another small hole is drilled on the other side of the casing and another pull is made. If it doesn't come this time a note is made of the stretch. If the pipe stretches 12 inches it is figured that 1200 feet is free and a charge of dynamite is lowered to this depth and the casing shot in two. The 1200 feet is then pulled.

Care should be exercised not to make too strong a pull. With hydraulic jacks or extra strong pulls a collar is simply stripped of its thread and this is all the pipe recovered, usually about 80 feet.

Fuel Economy Around Drilling Wells.

The cost for fuel oil is such an important item that companies engaged in carrying on extensive operations are beginning to pay more and more attention to the problem of cutting down fuel oil consumption at the drilling wells. This is particularly true in "wild cat" wells quite a distance removed from any source of fuel oil where long hauls have to be made to get the oil to the well. In quite a few localities fuel oil for "wild cat" drilling wells is costing as high as $6.00 per barrel delivered at the well. With an ordinary boiler consuming around fifteen barrels per day it can be readily seen that it is very important to save every barrel possible.

Feed water heaters.—There is a great waste of exhaust steam around any drilling well, particularly where the rotary system of drilling is being used. By connecting the exhaust from the pumps and engine to an ordinary feed water heater of which there are several good makes on the market a saving of 10 to 15 per cent in fuel bills can be very easily be effected.

Covering boiler with asbestos.—By housing in the boiler and covering same with asbestos cement a further saving can be effected. In covering an ordinary drilling boiler with asbestos cement it is customary to first cover it with ordinary chicken wire or expanded wire metal. Then the asbestos cement is mixed and applied to a thickness of 2 to 2½ inches. Some companies then wrap the boiler with muslin or cheese cloth to hold the cement in place and in some cases it is customary to cover the whole with thin sheet iron.

The steam lines leading from the boiler to the derrick floor should be placed at least one foot above the ground and should be insulated with 85 per cent magnesia or asbestocel pipe covering. The pipe covering is then wrapped with roofing paper to protect it from the weather.

By insulating the equipment as above recommended a fuel saving of 15 to 20 per cent can be expected. As this equipment should not cost much more than around $500.00, it can be easily seen that it will pay for itself in a very short time. Another very important item in this connection is that with these fuel economizers in use much drier steam will be delivered to the engine and pumps and they will be able to develop more power. At the same time in

some cases it will be found that operations can be carried on with smaller size boiler equipment than where no fuel economy is being effected.

The Blow Out Preventer[1].

Description of apparatus.—The blow-out preventer is a modified type of a stuffing box casing head, which in turn is an addition to the four-way T. The immediate object of the preventer is to control the flow of oil or gas between the two strings of casing, and naturally its use is better adapted to drilling by the rotary method in which the circulating water keeps an open space between the inner casing and the wall of the hole. An idea of its operation may be gained by imagining a four-way T attached to the top of the last casing set or landed and the inner casing passing through the T, the flow of oil or gas between the casings being deflected to the lateral openings of the T by closing the annular space between the inner casing and the upper part of the T by means of a stuffing box. In the preventer the stuffing box can be removed or put in place by turning the adjuster screws (Fig. 28-a) which operate slips (Fig. 28-b) provided with hydraulic packing that fit around the inner casing as an adaptable split valve. To the lower openings are bolted interchangeable screw flanges to fit standard casings from 6 to 12½ inches in diameter, and to the opposite openings are attached suitable guide plates (Fig. 28-c) to prevent the wearing of the inner parts of the apparatus by the revolving inner casing. These guide plates are made to fit casings from 8 to 2¼ inches in diameter. The lateral openings (Fig. 28-d) are threaded to fit pipe 6 inches in diameter. The apparatus is manufactured of cast steel and lined with babbitt metal, being tested to stand a pressure of about 2000 pounds per square inch. A wrench in two parts (Fig. 28-e) which are welded together to the required length, is provided to turn the adjuster screws (Fig. 28-a).

Mode of Operation.—To insure the successful operation of the preventer, careful attention must be given to all the details, such as welding the bars, fitting the small pins that secure the wrench to the screws, and providing a suitable place outside the derrick for the man who is to operate the wrenches, etc., as soon as the apparatus is put in place.

[1]Arnold and Garfias in United States Bureau of Mines Technical Paper No. 42.

The preventer, when used, is always placed on the last string of casing set or landed, thus controlling the flow between that string and the drill pipe or casing that is being lowered. The slips should be in a position to be clamped around the drill pipe, but should not be kept too near it, in order to avoid possible damage to the hy-

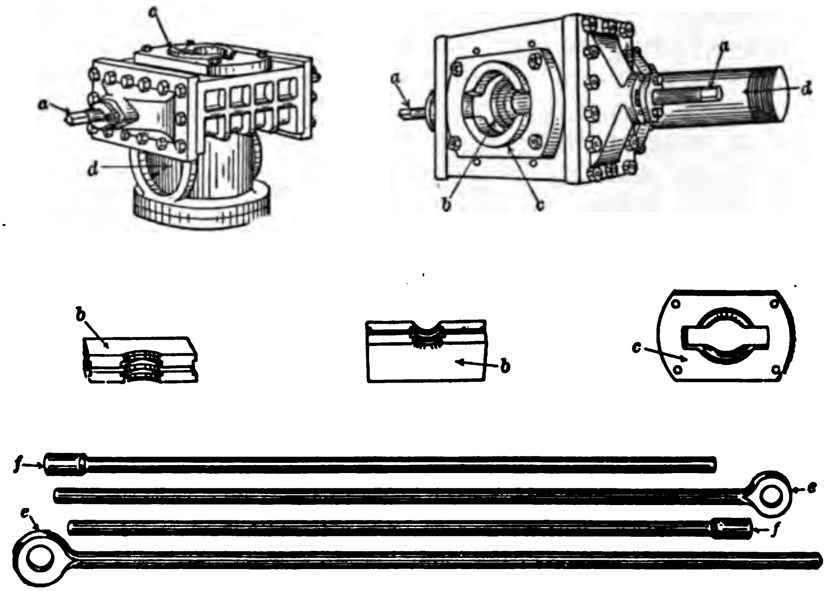


Fig. 28.—Blowout Preventer

draulic packing. If the well is being drilled with a rotary rig, the back-pressure valve, inside the drill pipe will effectively prevent any flow upward through this pipe ,and if the standard rig is used, a heavy gate valve, which can be closed after removing the drilling tools, is placed on top of the inner casing. The only outlet left is the space between the casings, and the flow through this opening can generally be controlled by clamping the split valve of the preventer around the inner casing and closing the gate valves on the pipes connecting the two lateral openings.

Sealing of artesian water or gas strata.—It sometimes becomes necessary to exclude from the drill hole water or gas found in ~~an~~ underlying sand in order to control the well or to recover or test for the oil below. This end can be easily accomplished in drilling with a rotary rig by forcing mud-laden water to the bottom of the well through one of the lateral openings of the preventer, the pressure

being regulated by closing the valve connected to the other opening. A back pressure valve in the drill pipe will prevent the flow of the mixture through pipe. By drilling short distances and forcing as much mud as possible into the porous sands penetrated, the wall of the hole through the gas-bearing or water-bearing strata is plastered with mud. After the entire thickness of the porous bed has been penetrated and the casing landed in an impervious bed, another string may be used to tap the oil sands below. The gas thus excluded can be recovered afterwards by drilling shallower wells to the upper sands.

This method can also be employed in drilling the entire thickness of a gas or oil sand under tremendous pressures, an operation that might otherwise prove troublesome. The mud can easily be removed by releasing the pressure or bailing down the water in the hole, a strainer or perforated casing being placed in the sand to prevent the wall of the well from caving when the pressure is released.

Testing of supposed oil or gas sands.—It is often advisable before drilling is continued to ascertain whether certain beds carry oil. The work involved is often accompanied by accidents and loss of time, as the material may collapse and pack around the casing, thus preventing its removal or further lowering. Many such accidents can be avoided and the required tests made by using a preventer or stuffing-box casing head in the following manner.

After the preventer has been attached to the last casing set, a special shoe about 8 feet long is attached to the bottom of the inner casing, and this is lowered to the bottom of the hole and driven down into the formation, making a water tight joint. The split valve of the preventer is then closed. A pump is attached to one of the lateral outlets, the valve on the other being kept closed to control the pressure in the well. Mud-laden water is then pumped in between the casings and the pressure is increased in order that the formation will not cave and "freeze" the inner casing. While the pressure is maintained the column of fluid in the inner casing is bailed out. This fluid being a representative sample of that which came from the formations passed through should show the presence of oil if any has been encountered. Great care should be exercised in bailing out, as the casing may happen to be in such condition that it will not withstand the outside water pressure.

THE CABLE TOOL SYSTEM OF DRILLING.

This system of drilling wells is so widely known that a detailed description of it hardly seems necessary.

Surface equipment.—The standard drilling rig used in the operation of a string of cable drilling tools is shown in Fig. 29. The

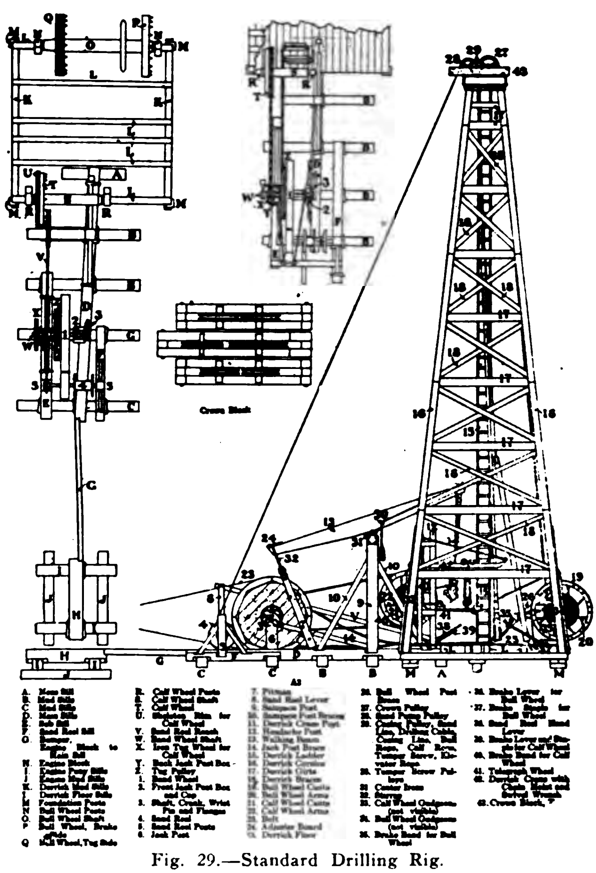


Fig. 29.—Standard Drilling Rig.

derrick can be any height from 60 to 120 feet, but the 84-foot derrick is most commonly used. The drilling motion is imparted by the "up and down" movement of the walking beam. The crank on the band wheel shaft operates the walking beam, being connected with it by a pitman. The length of stroke of the tools is controlled

by moving the wrist pin back and forth along the crank. This crank is rotated by the band wheel which is belt driven from a steam engine or electric motor. The steam engines are ordinarily of the single cylinder slide valve type, varying in size from 10½x12 to 12x12, and in some cases being as large as 16x16 for extremely deep holes. The engine is controlled from the derrick floor by means of a reversing lever and "telegraph cord" attached to the engine throttle. A tug rim is attached to the band wheel on the side opposite to the crank arm. This is used for transmitting power by rope drive to the bull wheels on which the drilling cable is spooled. To this same side of the band wheel is also attached the sprocket which drives with a chain a corresponding sprocket on the calf wheel. The calf wheel is used for raising and lowering casing. The "sand reel" on which the bailing line is spooled is also operated from the band wheel, being operated by a friction drive. On top of the derrick is the crown block which quite commonly contains six shieves. Four of these shieves are for the accomodation of the casing line operated off of the calf wheel. The large shieve in the center of the crown block accomodates the drilling line, and the other one accomodates the "sand" or bailing line.

From the end of the walking beam which projects inside the derrick the temper screw is suspended. The drilling clamps which hold the drilling cable are attached to the lower end of this temper screw. The temper screw ordinarily has a "let out" of 60 to 70 inches, and the progress in drilling hole is made by "letting out screw" or unscrewing same through a threaded box.

The drilling tools.—A "string" of cable drilling tools which is about 40 feet long, consists, ordinarily, of a bit, auger stem, drilling jars, and rope socket. These tools are joined together by "tool joints." As it is very necessary that the joints be made up very tightly a special jack working on a circular track is used to screw them together on the derrick floor. Each tool has a "square" on it at each end immediately below the box or pin of the tool joint, and specially made wrenches are fitted to these squares in the "making up" of a "joint." The rope socket is connected to the drilling cable. This attachment with a manila line is commonly made through a "woodpecker" socket. With a wire drilling line the connection is made by babbitting the end of the line into the

socket. Most drillers now prefer to use the swivel rope socket with a wire drilling line. This type of socket permits the twist of the wire drilling line to adjust itself and makes the handling of the tools much easier. The wire drilling lines are commonly made of six strands of 19 wires each wound around a hemp core. The wire going into these lines varies in composition but it is commonly crucible cast steel. The drilling lines vary from ¾ to 1 inch in diameter.

The actual operation of drilling is accomplished by raising and lowering this string of tools, the blow delivered by the tools striking the rock shattering it and the subsequent strokes further pounding it up. The drilling line is attached to the temper screw which in turn is suspended from the walking beam, as has been mentioned. The speed of the drilling engine governs the number of strokes per minute of the walking beam and the rate of drilling. The regulating of the engine speed so as to get the correct "drilling motion" is quite an art and is discussed by Curtin as follows:

Discussion of "Motion" In Drilling[1]

"The following hints on the running of tools may be of service to many drillers, although it is acknowledged that the skill necessary for efficiency can be gained only through practice.

"'Motion' is the engine control applied by the driller in the raising and dropping of cable tools. A driller who thoroughly understands motion has mastered his trade so far as the operation of the drilling tools is concerned.

"With each added foot of hole there is an almost unnoticeable change in motion. As the depth of the hole increases, the difference in motion becomes evident when compared with the motion carried at a shallow depth. The adjustment of the steam power to the fall of the tools changes with every variation of the hole.

"When drilling in a dry hole, with a manila line, control of the tools becomes more difficult as the depth increases; the engine becomes 'weaker' with the greater load caused by the increased depth of hole.

"As a premature use of engine balances retards the drop of the tools and compels a slower motion, the common practice among experienced drillers is to avoid the use of the balance in dry-hole, manila-line work where the formation stands up, so long as they can keep the engine 'on its feet' without being compelled to run the tools too 'loose.' With an ordinary drilling engine, when a depth of 2000 to 2500 feet is reached without the use of a balance, great skill in steam control is required to maintain the proper motion, or, in fact, any workable motion.

"If the opposing drillers, on different tours or shifts, are not equally

[1]By Thomas Curtin, United States Bureau of Mines, Bulletin No. 182.

skilled in steam control, or, as it is termed, in handling the engine the sensible procedure for the driller having trouble in maintaining the proper motion is to swallow his pride and resort to the use of the balance when he comes on tour, allowing his mate to take the balance off or leave it on at his discretion.

"When an engine begins to become unmanageable, time is saved by putting on a balance, and the danger of compulsory loose running in order to retain engine control is averted.

"The same rules that apply to manila-line drilling, as regards motion and balances, do not apply when using a wire line. The 'reach' and 'take up' of a manila line exceeds that of a wire line. In wireline drilling, the weight of tools and other conditions being the same, the use of balances at lesser depths than would be required with a manila line is a distinct advantage.

"The early use of balances with a wire line is especially recommended where drilling jars are run. The quick snap given the tools on 'catching' them before they strike, by an occasional excess of motion difficult to avert, often causes the jars to break. The tendency to catch the tools from an excess of motion with the wire line is greater with a 'weak' engine. Besides, when using a wire cable it is necessary for the driller to follow more closely the jar observed at the surface. The lack of stretch in the wire line, if the drilling is 'good,' requires more constant letting out of the screw.

"The 'reach' and 'take up' of a manila cable makes the striking of bottom possible with such a cable long after the bottom would have 'faded' before the stroke of the tools on a wire line. The 'reach' of the manila cable is easily described by what the older drillers call 'lift.' For example the tools would be running 'loose' and permitted to 'pound.' As the tools 'drilled off' and commenced to 'reach' a noticeable 'lift' could be observed after the jar was received at the surface. This lift would feel much as if the handlebar of the screw had exceeded the usual height, which in reality could not occur. As this lift is a demand for 'screw,' if screw is withheld there will be a slight pause in the motion, soon followed by the engine's being 'off its feet,' thus compelling screw.

"'Lift' is explained as follows: As the tools begin to 'reach' on the downward stroke the cable lets out. When the tools strike, the elasticity in the manila cable causes a "taking up" of stretch at the reaction of the tools. Drillers contend that this 'taking up' of cable stretch is in reality what is felt at the surface as lift.

"With the wire line, except at great depths, the nearest parallel to the lift of a manila cable in a dry hole is 'peg-legging' (alternate hitting and missing of the tools). Tools will peg-leg with the wire line, but should not be permitted to do so in a dry hole under ordinary conditions.

"If the motion is normal, when the tools 'drill off' they will peg-leg; this is a demand for screw. Peg-legging can also be caused by a lack of motion. If there were more reach to a wire line, the tools would not

peg-leg so readily. An excess of motion when tools are peg-legging will result in catching of the tools, with danger of breaking the jars.

"Both lift and peg-legging are to a great extent dependent upon depth. Lift is seldom discernible above 500 feet. Tools do not easily peg-leg above 300 feet under correctly applied motion.

"Many drillers contend that there is little to the mastery of motion with the wire line. As a rule such men, owing to long experience, regulate the motion automatically. Wire-line drilling, however, requires the same mastery of motion—perhaps more easily acquired—as the manila line.

"The most common error of the novice with the wire line is the catching of the tools. This is also a common error of drillers accustomed to using a manila line and to the solid jar of the tools in a formation that stands up, when they change to soft and wet hole drilling in wire-line territory. They often mistake the catching of the tools for the solid jar they seek and to which they are accustomed, with the result that they 'jack' the line or break the jars, or, in the event of no accident, fail to make progress until they have fathomed the trouble.

"The types of formation that a driller must combat vary so greatly that it is impossible to give hard and fast rules for his guidance. In 'mud countries'—on the assumption that a wire line is always used where mud and water are encountered—it is advisable to hold the tools up. Some formations are such that when a distinct jar is noticeable further progress, without bailing, is impossible, as this jar indicates that the tools have started to 'load up.' With continued running the jarring becomes more noticeable, but the tools are making no headway.

"Where sticky blue shale is encountered and the tools tend to stick with every revolution of the engine, keeping the motion as rapid as can be safely carried will be found of assistance. Drilling through a formation of this type is necessarily hard on equipment and timidity becomes a greater fault than boldness.

"A false jar often occurs in cleaning out muddy and caving holes. As this jar occurs on the down stroke, it is probably caused by the motion exceeding the drop of the tools for an instant; the tools are momentarily retarded with mud, but regain sufficient velocity to keep pace with the engine. No attention, within reasonable limits, should be paid to such jarring, because if the motion is slowed up to conform to the drop of the tools and the jar thus eliminated, the velocity of the tools is so retarded that they merely slide up and down in the mud and water without doing work. Therefore, it is essential to carry sufficient motion to mix the mud with water and to prevent the tools from loading up."

Use of jars. Drilling and fishing.—"Drilling jars are of short stroke and are run above the stem. They are always used extended in drilling, and their chief purpose is to aid in 'switching' tools loose when the tools are stuck. As the weight above that part of the drilling jars which receives the blow, is usually only that of the rope socket and the upper half of the jars, and as the stroke of the jars is only a matter of a few inches—4 to 12

inches, as a rule—a very strong blow can not be expected from their use.

"Fishing jars are run on the bottom of the stem. Their usual stroke is 36 or 48 inches, although nearly any length of stroke is obtainable. The force of the blow obtained by the use of fishing jars is governed by hitch, stroke, weight of stem, and motion.

"In fishing where 'jarring' is expected the engine should be balanced except at very shallow depths. This will insure the engine having enough driving power to do its work under any sudden increase of load. In 'jarring up,' a 'weak' engine results in the belt slipping or being thrown when the beam 'turns over' before the 'hitch' has been regulated by the screw.

"A stem of suitable size and weight for the work expected should be provided, and special attention should be given to the pins and boxes of all tools. The wrist-pin adjustment in the crank shaft should be changed to conform with the stroke of the jars and the length of blow desired. Let it now be assumed that the fishing tool has taken hold of a stationary object at the bottom of the hole and that it is desired to jar up. The 'hitch' is obtained by raising the tools with the bull ropes until the jars strike up. Then a hitchstring is tied to the cable at a point even with the top of the hole; the tools are backed slowly down the hole a few feet; the engine is reversed, and the tools started quickly upward. When the string appears at the surface, the bull ropes are thrown. A few inches of slack is then run into the hole, care being taken not to run in enough slack to permit the jars to strike downward upon the 'turnover' of the beam after clamping on, then clamp on, 'rock' the engine to ascertain whether enough slack has been provided to prevent too great a line tension on the rig, regulate the 'hitch' with the screw satisfactorily, and start the beam to turning over. The screw is regulated until the 'jar' received at the surface is satisfactory; from then on the force of the blow is governed by regulating the motion of the engine.

"To 'drive' or jar down, follow the same procedure as in jarring up, with the following exceptions: In taking the 'hitch,' ascertain at what point the jars strike down, instead of up; tie a string onto the cable when it is even with the top of the hole when the 'down' contact of the jars is received; then clamp on at this point.

"In driving down if the hitch has been judged accurately, the 'jar' will be received at the surface almost simultaneously with the impact of the jars at the bottom of the hole. If after the 'jar' is received at the surface the driller observes that several inches of cable travel into the hole before the down stroke is completed, he can judge that the hitch is as about an equal distance 'loose'."

Use of bailer in cable drilling.—After drilling 4 or 5 feet, or until the tools begin to "stick," the tools are withdrawn from the hole after disconnecting the temper screw and removing the pitman from the crank. The removal of the tools is accomplished by "throwing on" the bull ropes which drive the bull wheel from the band wheel.

The rotation of the bull wheel winds up the drilling cable. The bailer is then run into the hole and the cuttings are bailed out. Sufficient water is then lowered into the hole for the proper mixing up of the cuttings. Then a sharp bit is put on the string of drilling tools, if needed; the tools are lowered into the hole and drilling is resumed.

Drilling With Cable Tools In Soft Sands[1]

Cable system generally used in wildcatting.—Good practice demands that cable tools be used on any test well in an unknown or wildcat district. If the approximate depth of the stratum which is thought to be oil-bearing is known, or if the depth is decided by contract with the landowners, a standard or calf-wheel rig is erected of a size and type commensurate with that depth and drilling commenced with cable tools. If the territory proves to be suitable for cable tool work and stands up, the well progresses satisfactorily and rapidly as a rule but if caving and unconsolidated sands are encountered, complications surely follow. These unforseen contingencies will be treated briefly.

Freeing frozen casing.—The 8¼-inch casing is frozen. The first thing to be done is to attempt freeing it. Alternate pulling and driving may accomplish this. The power of a calf wheel applied through seven lines to the heavy casing block is tremendous and an expert driller knows just the amount of stretch the casing will withstand before parting. If it comes an inch or two the drive clamps are adjusted on the square of the stem and the casing driven back to its former position, when it is again pulled, possibly yielding an additional inch. The principal thing is to cause it to move even slightly, as it is sure ultimately to become free by this method. It is well to apply the casing tongs after each pull or two and set up the entire string a trifle. This tightens any threads that may have become loose.

It frequently happens that the alternate pulling and driving method proves futile. The casing refuses to move an inch. In this event other methods are at the command of the engineer. One that is often successful and is not commonly known is to relieve the static pressure within the casing, it being presupposed that the hole is full or nearly full of fluid, and allow the sand to heave within the drilling string. It is seldom necessary to bail more than 300 or 400

[1] Wm. Kobbe in Trans. American Institute of Mining Engineers, Vol. LVI, p. 799.

feet of fluid from the well in order to so disturb the balance of pressures that a sudden upheaval of the oil sand takes place. Following this upheaval the driller tries the casing and if it is free, which is nearly always the case, the hole is cleaned out to bottom and drilling resumed.

It sometimes happens on account of insufficient pressure in the sand, or from other causes, that the sand fails to heave when the static pressure is reduced. In that event a casing spear, preferably of the trip type, is run to bottom on the tools and engaged near the shoe, with long stroke jars and sinker bar or stem giving necessary impact to the jars. A strong pull is then taken with hydraulic jacks applied to the casing by means of a spider, while jarring is commenced on the tools. This method will free exceedingly tight casing. A nail may often be driven out when it cannot be pulled. The jarring of casing is exactly similar.

If this method fails to free the casing, a spear may be run on a string of the next smaller size casing and a hold secured near the bottom of the frozen pipe. A heavy pull is then taken on both strings of casing while jarring is commenced with the tools which carry long stroke jars and a casing spear as described in the previous method. In fact, the two methods differ only in that a much stronger pull can be taken on the two strings of casing than on the one; in other words, the pull is doubled.

In rare cases it happens that the unconsolidated sand holds the casing in such a grip that even this tremendous pulling force and the heavy jarring, which may be likened to the blows of a steam hammer, fail to free it. As a last resort the casing may be split in several places to allow the binding sand to run into the well. To accomplish this a casing ripper is run in on the tools and several long gashes cut in the casing at a point where it is thought the maximum "friction" exists. If this results in the entry of sand it will nearly always free the string.

In the event that all these attempts fail and it is impossible to free the casing, two methods of overcoming the difficulty remain. A 4-wheel casing cutter may be run in on 3-inch tubing and the casing cut at a point just above where it is frozen. The upper portion of the string is then removed from the well, a new shoe adjusted and the joints imbedded in the sand "side-tracked" or drilled past. This is slow and difficult work and not always suc-

cessful. Some operators shoot the casing instead of cutting it. A small charge of dynamite is exploded at the point where the casing is frozen, but this results in jagged ends at the place of rupture, making the casing more difficult to side-track. It is a quick and inexpensive method but cannot be considered good practice in many cases.

If it is not desired to cut or shoot the frozen string, the only thing to be done is to abandon it and case with the next smaller size pipe. This is permissible providing the frozen string is of such a size, say 8¼ or 6⅝ inches, that the well may be completed to the required depth before "pointing out."

Loose oil sand under pressure often heaves in a cable tool drilling well when the bit drills through the cover rock, and unless the driller is warned in time the tools are buried for many feet by the sand. In certain of the California fields the oil sand has often buried a string of tools 300 feet or more and frequently led to a bad fishing job. Whenever such sands are anticipated the experienced driller "carries" the hole full of water or thin mud slip in order to counterbalance the rock pressure. The jars and sinker bar are also used on the tools so that in case of a sand heave they may be jarred free. It is sometimes necessary to jar the tools through 100 feet or more of oil sand, which requires possibly 12 to 24 hours. If the wire drilling line parts a bad fishing job is apt to result and it may be necessary to pull the casing (if it is free) in order to recover the tools. Or if it is frozen a "fishing string" is run in, after cleaning out to the top of the lost tools, and an attempt made to recover them with a socket or other special fishing tool. This is simply an example of one of the many fishing jobs of endless variety that may occur from the heaving of unconsolidated oil sand. These same remarks apply with equal force to conditions arising from the penetration of any unconsolidated sand or other material of a cavey nature which may freeze casing or bury cable tools.

Rules governing the drilling of deep test wells.—A few general rules and cautions governing the drilling deep test wells in wildcat territory where unconsolidated sands are expected, follow:

1. Allow a wide margin above the calculated cost of the well.
2. Commence drilling with a sufficiently large hole, 20 to 22 inches for a deep test.
3. Do not expect a light rig for shallow territory to drill a deep test.

4. In remote districts have all the casing on the ground and an adequate supply of small tools, pipe and fittings.

5. Have a rope grab, combination socket and other frequently needed fishing tools available for instant use.

6. After selecting the site for the rig, have a cellar dug about 8 by 10 feet by at least 15 or 20 feet deep. The depth is important.

7. Provide an adequate supply of the best obtainable water for steaming purposes.

8. Anticipate heavy oil or gas pressure and have a control casing head on hand if occasion arises for its use to cap the well.

9. Locate a deposit of fine clay for use in mixing mud slip to shut off pressures or to use while drilling in unconsolidated sands that refuse to bail readily.

10. If the well is to be drilled by a contractor at so much per foot, do not expect sands tested, water shut off, and logs kept as carefully and efficiently as would otherwise be done. Many important features of the work are slighted and the time required for their proper accomplished sacrificed in the effort to make the maximum amount of hole in the minimum time.

11. Carry every string of casing to the maximum depth possible and never abandon the effort until every means at the command of the operator has been exhausted in the attempt.

12. The management of the work, selection of methods, etc., should not be left to the drillers but placed in the hands of a competent superintendent.

13 Keep a most careful and accurate log of the well, preferably in several copies in order that if one is lost the record may be preserved.

Taking up some of these points in more detail: In allowing for the cost of a test well in wildcat territory a safe rule to follow is to figure the actual cost as accurately as possible and multiply this figure by two. How many wells are reported as "abandoned for lack of funds?" It is safe to say that unconsolidated sands or other cavey materials are responsible for a large percentage of the failures and for most of the difficulties, discouragements and delays in the drilling of test wells. Many wells that "ought not to cost $15,000" actually require the expenditure of $25,000 to $30,000 for their completion. Much larger amounts are not at all unusual and it is well to keep in mind that figuring the cost of a test well in a wildcat district is a good deal like provisioning an exploring party to penetrate unknown wilds—emergencies must be anticipated in both cases.

The importance of commencing the well or "spudding in" with a sufficiently large hole cannot be overestimated. In order to reach

the desired depth, whether 2500 or 4000 feet, it is imperative to make the size of the hole at the surface commensurate with the depth. In the soft Tertiary formations of California and in the Baku fields of Russia it is found advantageous to use large-diameter stovepipe casing for the first few hundred feet, especially where beds of boulders are encountered. This type of casing is made by riveting sheet iron or steel of 14 to 10 United States gage and may be purchased in lengths of 2 feet or multiples of 2 up to 20 feet, the shorter lengths being used when progress with the string becomes slow. In the Russian fields, wells are commenced with holes of extremely large diameter, not on account of any extraordinary depth but in order to complete a well in the pay sand of sufficient diameter to permit the use of large-sized bailers. The method used in that country to bring the oil to the surface, because the excessive amount of unconsolidated sand precludes the use of pumps. The usual sizes of the California stovepipe casing are 16, 18 and 20 inches, and if 500 to 700 feet of the 18-inch size can be put in a well the operator has a good beginning for a deep test in unconsolidated formations. A great advantage possessed by this type of casing is the absence of collars with a consequent reduction in friction, making it especially suited for driving through strata of unconsolidated sands. Its use will probably extend to Oklahoma and the Mid-Continent fields as development extends westward into deeper territory possessing all the problems arising from the presence of unconsolidated sands or other strata of loose materials. Many test wells have been and are being drilled in the Permian Red Beds of Western Oklahoma and the occurence of deep deposits of unconsolidated materials in this region is gradually bringing about improved drilling methods and the introduction of more efficient mechanical devices. For the same reason, operators accustomed to the hard strata of the Eastern fields where casing problems are of small importance are realizing the necessity of large-diameter holes and the use of heavy-weight pipe with improved methods of handling it. Commencing a test well with too small a diameter means that it "points out" before it "tests" anything. In Pottawatomie County, Oklahoma, a typical wildcat section, are many abandoned "test" wells that pointed out before a depth of 2500 feet was reached, although it was known that if oil occurs it would be found at 3000 feet or more. These failures were all due to the fact that

the holes were commenced with diameters too small and that the presence of unconsolidated sands was not taken into account. These sands necessitated the use of a greater number of string of casing which in turn caused the well to point out sooner than would have been the case had it been commenced with a hole of larger diameter. "It may be said in conclusion that in drilling in wildcat territory where the number of water and gas sands is unknown and the depth of the oil sand uncertain, and therefore the ultimate depth of the hole cannot be known, one must start with a larger size of casing than that which will probably be used for later wells when the field is developed. Pioneer wells have been drilled in some pools, which failed to discover oil because the hole was so small it could not be carried deep enough to penetrate the sand which was later discovered to be the main oil pay, perhaps only a few feet beyond where the early well stopped drilling. Wells in the Calgary district in Alberta are started with 18-inch casing. In California even larger casing has been used."

Probably the best type of rig for handling heavy strings of casing in unconsolidated sands is the California or calf-wheel with sprocket drive and extra heavy rig irons. A light standard rig such as is commonly used in the Eastern fields and parts of Oklahoma is sufficiently strong to handle light-weight strings of casing through consolidated formations but is totally inadequate for the heavy pulls required to free long strings of California pipe in contact with several hundred feet of unconsolidated sands. For the heaviest work, iron or oak calf and bull-wheel shafts are required, and concrete foundations for the derrick. The usual practice of placing a few pieces of waste lumber under each derrick leg as foundations should not be countenanced, especially where the casing may have to be carried through cavey material with the consequent heavy strains which inevitably result in pulling the derrick out of plumb.

A feature connected with cable-tool drilling in unconsolidated sands which many operators, accustomed to hard formations, overlook, is the importance and advantage of an adequate cellar. When a string of casing is being carried through sands or other cavey material it has to be "worked" almost continually and sometimes freezes while one "screw" is being run. It is difficult or impossible to make any hole ahead of the shoe and frequently the casing is allowed to "follow;" that is, it is released from the spider slips and

follows the drilling bit of its own weight. If it refuses to follow it is worked up and down with the casing block and calf wheel and sometimes spudded with a jerk-line or driven with the drive clamps and tools. In all of these operations a deep cellar is of the greatest advantage because it allows the driller to work the casing below the derrick floor until there is sufficient clearance for another joint to be screwed on. Casing averages about 20 feet to the joint, hence a cellar of approximately that depth is most desirable, although 15 or 18 feet is a great improvement on the inadequate and shallow pits commonly placed under derricks in regions where the problem of unconsolidated sands is unknown or underestimated.

Finishing a well in unconsolidated sands.—The process of finishing a well in an unconsolidated pay sand is quite different from the "bringing in" of a well tapping a hard sand. It sometimes requires weeks to penetrate a thick stratum of loose pay sand with cable tools, whereas the "drilling in" and "shooting" of a hard sand is a much simpler process. Where the sand, whether loose or hard, is under great pressure and the well "comes in" as a gusher or flowing well as soon as the sand is tapped, the results are exactly similar except that the well in the unconsolidated pay is apt to throw out quantities of sand.

The finishing of a well with cable tools in a very thick stratum of unconsolidated oil pay is much more of a problem than where a rotary is used. The ordinary procedure, especially in districts where screen pipe has never been tried or is unknown, is to carry the casing, of the size the hole is to be finished with, through the oil sand and then perforate it with a perforating machine. It frequently happens that the string freezes after penetrating the sand for 100 feet or less, in which event it is usual to place an iron or wooden heaving plug in the bottom of the casing and then perforate. If the operator is fortunate enough to carry the casing through the pay it can be landed in the stratum underlying the sand, which obviates the use of a heaving plug, the only function of which is to prevent the sand heaving inside the casing and overwhelming the pump. Irrespective of the depth of sand attained, the use of the perforator is necessary with this method and is its greatest drawback, mainly on account of the uncertainty of the results therefrom. For mechanical reasons, variation in the thickness or toughness of casing, and other factors beyond the control

of the operator, the use of a perforating machine is frequently disappointing. If the well comes in as a small producer there is always the suspicion that the perforator failed to punch a sufficient number of holes, whereas if the casing "sands up" and the well requires constant "pulling" the reverse is true. Arnold and Garfias mention these points in describing methods of oil recovery in California: "The indiscriminate use of perforating machines has been the source of much trouble. In the Coalinga field one well about 1300 feet deep was perforated three times, and when the casing was removed it was found that, except for a few holes, the machine had only indented the casing. In other wells, owing to local brittleness of the casing, the perforator has removed large pieces of it; and in some deep wells, owing to the great weight of the column of tubing to which the perforator is attached, the perforator has cut into or strained the collars so as to cause collapse of the casing."

In the light of these facts and of past experience in drilling many wells in unconsolidated oil sands, it may be said that every effort should be made to avoid bringing in the well by perforating the casing after it has been placed in the hole. As a substitute for such perforating the operator may use screen pipe or shop-perforated casing. In finishing a cable tool well with either of these two devices the problems involved are largely or entirely dependent upon the thickness of the unconsolidated sand. If this sand is a thin bed, 50 feet or less in thickness, there is usually no difficulty in setting any type of screen or of shop-perforated casing, but where the sand is 250 to 300 feet thick many obstables may be encountered.

The ideal method of finishing a cable tool well in a very thick stratum of loose pay sand is to carry, say, 8¼-inch casing through the pay and then set 6⅝-inch liner, either screen or shop-perforated, preferably the former, inside this 8¼-inch and then remove the 8¼-inch casing, leaving the liner in contact with the oil sands. This is very difficult to accomplish, however, because it necessitates the keeping the 8¼-inch free at all times, and this is seldom possible. In fact, it may freeze beyond all power of freeing while the liner is being set.

It well may be asked, why not carry 8¼-inch screen or shop-perforated pipe through the sand in the first place and thus save the extra labor of setting a liner and gain the advantage of com-

pleting a well of larger diameter. The answer is that it is much more difficult to carry perforated than blank casing through unconsolidated sands and that all types of screen pipe possess the same objection. In addition, certain screens are not made to withstand such work and are easily damaged, necessitating the use of a conductor casing when setting.

Drilling In North Texas.

There has been much written relative to the producing fields in the Pennsylvanian area of North Texas, both from a geological and a financial standpoint, but next to nothing has appeared in print relative to the technical side of this industry. Very few people are aware of the difficulties that arise in drilling in this country, and fewer still realize what the cost of drilling really is. It is the object of this article to give some of the operating details concerned with the drilling and bringing in of wells in the North Central Texas area. This will include the current practice in such fields as Desdemona, Ranger, Breckenridge and Caddo, as of June, 1919; but no mention will be made here of methods of operating in the Burkburnett area, where the practice differs radically from that in the above mentioned fields.

Method of drilling in North Central Texas.—Men from all parts of the United States are working in North Texas both as drillers and as foremen or superintendents in charge of work. This gives rise to keen rivalry and California ideas are daily being pitted against Oklahoma and Pennsylvania ideas. Out of this melting pot of eastern, northern and western methods some very efficient ways of doing things are being developed.

The standard cable tool system of drilling is universally used in the area under consideration (Ranger, Desdemona, Breckenridge, Caddo and adjoining territory). The rotary system of drilling has been tried out at Desdemona, Brownwood, Moran, and in one or two other places but with only indifferent success.

Tools needed for drilling in North Texas.—Wells to be drilled to a depth in excess of 3500 feet in North Texas are now starting with a 22-inch hole and setting some 20-inch pipe. This requires 20-inch bits and means that large tool joints will be needed to stand the vibration. In the early days of the development small joints were used on large bits and many pins were "jumped" as a consequence. The writer remembers, in the early days of Ranger, seeing over 50 auger stems laying outside a certain tool company's

shop with battered boxes, and 50 bits stacked nearby with "jumped" pins.

The standard tool joint in use in North Texas on large bits is the 4x5 inch joint, threaded 7 threads per inch, I. & H. This is used on bits from 20-inch to 10-inch in size. Of course, due to inexperience, pins will be "jumped" using this large size joint. However, if care is used in dressing to see that the bit is moon-faced just a little and care is exercised in running to see that the driller does not "hitch too loose," very few pins will be broken.

FIG. 30—DEEP WELL DRILLED WITHOUT DERRICK

Derricks and standard rigs are not absolutely necessary in the drilling of North Texas deep wells. This well was drilled to 3980 feet with a No. 30 Star drilling machine in Stephens County, Texas. Near Mineral Wells, Texas, Owens & Wilson drilled their No. ! Oaks to 4555 feet with a National drilling machine. However, long strings of pipe cannot be handled with this kind of equipment. On the left will be seen a control head capping the well.

The 8¼-inch and 6⅝-inch bits use a 2¾x3¾ pin, 7 threads, I. & H.; and the 5 3-16-inch bits use a 2x3-inch joint, 7 threads I. & H. All bits should be of the Mother Hubbard pattern. The familiar bottle-necked bit of California will sooner or later get the driller in trouble in North Texas when he gets "mudded up."

It is getting to be quite the practice in North Texas to use a 5½-inchx30-foot auger stem with a 4x5-inch box and 3¼x4¼ pin

This permits using 6½-inch drilling jars with 3¼x4¼-inch box and pin, which is heavy enough. Some operators use jars with 2¾x3¾ joints in the "big" hole.

All fishing and underreaming tools in North Texas for 6⅝-inch and larger diameter hole have 2¾x3¾-inch joints, 7 threads I. & H.

In most all of the fields 10-inch and 8¼-inch casing are underreamed, so it is very customary to furnish underreamers of these sizes with the tools.

Herewith is given a complete list of tools that will be needed to drill an ordinary well in North Texas, together with their cost on June 15, 1919:

1—40 horsepower, locomotive type, oil country boiler with guy wire, stack fittings and grate bars..........................	$ 1,450.00
1—12"x12" oil country drilling engine with cross head pump, heater and extra balance rims..............................	545.00
1—6"x4"x6" general service duplex pattern steam pump..........	250.00
1—1 kilowatt steam turbine driven electric generator............	270.00
1—⅞"x4000' 6x19 crucible steel drilling line....................	960.00
1—9-16"x4000' 6x7 steel sand line at 10 cents....................	400.00
1—⅞"x750' 6x19 steel casing line..............................	180.00
1—12" 6-plyx90' stitched rubber drilling belt....................	205.00
2—2½"x90' manila bull ropes	55.00
1—Set 15½" Fairs-Mannington Csg. Elevators....................	265.00
1—Set 12½" Fairs-Mannington Csg. Elevators....................	190.00
1—Set 10" Fairs-Mannington Csg. Elevators	180.00
1—Set 8¼" Fairs-Mannington Csg. Elevators..................	160.00
1—Set 6⅝" Fairs-Mannington Csg. Elevators....................	117.00
1—Set 5 3-16" Fairs-Mannington Csg. Elevators................	85.00
1—30" three-sheave casing block—1250 lbs......................	175.00
1—5" 360-lb. double swivel casing hook.........................	84.00
1—20"x5' steel drill bit, 5" square, 4"x5" joint, 7 threads, I & H weight 2400 lbs.	408.00
2—18"x6' drill bits, 5" square, 4"x5" joint, 7 threads..............	748.00
2—15½"x7' drill bits, 5" square, 4"x5" joint, 7 threads............	544.00
2—12½"x7' drill bits, 5" square, 4"x5" joint, 7 threads............	459.00
2—10"x7' drill bits, 5" square, 4"x5" joint, 7 threads............	390.00
2—8¼"x7' drill bits, 4" square, 2¾"x3¾", 7 threads..............	232.00
2—6⅝"x7' drill bits, 4" square, 2¾"x3¾", 7 threads..............	170.00
2—5"x7' drill bits, 3" square, 2"x3", 7 threads...................	112.50
2—5½"x30' Auger Stems with 4x5 box and 3¼x4¼ pin, 7 threads I & H, 5" square...	523.42
2—4¼"x30' Auger stems with 2¾x3¾ box and pin, 7 threads, I & H 4" square	290.00
1—3½"x30' Auger stem with 2x3 box and pin, 7 threads, I & H, 3" square..	111.00

½"x8" stroke drilling jars with 3¼"x4¼" box and pin, 7 ıds, 5" square	135.90
½"x4½" stroke drilling jars with 2¾x3¾ box and pin, 7 ıds, I & H, 4" square	94.63
¼"x5" stroke drilling jars with 2x3 box and pin, 7 threads H, 3" square	85.00
½"x36" stroke fishing jars with 2¾"x3¾" box and pin, reads, I & H, 4" square	156.75
Prosser swivel socket 3¼"x4¼" box, 7 threads, I & H quare	85.00
Babcock socket, same joint as above	39.20
Prosser swivel socket 2¾"x3¾" box, 7 threads, I & H quare	65.00
Babcock stiff socket, joint as above	42.50
Babcock stiff socket, 2x3 box, 7 threads, I & H, 3" square	16.50
6' Ball and Dart Bailer	262.00
0' Ball and Dart Bailer	168.00
' Ball and Dart Bailer	183.00
' Ball and Dart Bailer	98.00
30' Ball and Dart Bailer	73.50
30' Ball and Dart Bailer	45.50
3it Gauge	5.75
3it Gauge	5.00
Bit Gauge	4.55
Bit Gauge	3.85
3it Gauge	3.36
Bit Gauge	2.80
Bit Gauge	2.52
6" Bit Gauge	2.13
Oilwell improved temper screw with "T" head, less ıps	126.00
nachine drilling clamps with liners for ⅞" wire line	80.00
?" inserted temper screw slips	13.20
;" square 350-lb. tool wrenches with 4" liners	83.80
;" square wrenches	45.00
x12' derrick crane	60.00
on anti-friction chain hoist	70.00
s pulley and clevis	4.00
line spudding shoe and ring	17.00
:asing wagons	40.00
? Barrett jack and circle complete	102.00
). bit ram	60.00
derrick forge	75.00
homa pattern steel tool box	75.00
slack tub	60.00
b. combined anvil and underreamer lug dressing block 10" and 8¼" lugs	80.00

1—15½" spider and slips for 15½" and 12½" pipe and liner and slips for 10", 8¼", 6⅝" and 5 3-16" pipe	520.00
1—Set Santa Fe back-up tongs	90.00
1—Pair Dunn "B" tongs with jaws for 10", 8¼", 6⅝" and 5 3-16" pipe	215.08

Fishing Tools:

1—10" slip socket, 2¾x3¾ pin, 7 threads I & H, 4" square, 7⅛" bore, 2 extra sets slips	255.00
1—12½" bowl for above	25.50
1—15½" bowl for same	34.50
1—8" slip socket, same pin and thread as above and with 6⅝" bore, 2 extra sets slips	150.00
1—6¼" combination socket, same joint as above and equipped with pin and socket neck slips	78.75
1—8" center hole spear same pin as above	60.90
1—6¼" three-prong grab	90.00
1—6¼" latch jack, same pin as above	42.75
1—6⅝" steel die nipple, male and female	26.12
1—8¼" steel die nipple, male and female	27.68
1—10" steel die nipple, male and female	40.38
1—12½" steel die nipple, male and female	73.68
1—8¼" spud with 2¾"x3¾" pin	121.60
1—Acme wire rope knife	185.00

Underreamers:

1—10" Union double underreamer	525.00
2—Sets cutters for above	179.00
1—8¼" Union double underreamer	448.50
2—Sets cutters for above	142.50
1—6⅝" Swan underreamer with two sets extra cutters	307.75

Derrick Tools and Appliances:

1—No. 4 Star blower	32.35
1—No. 2 Barrett swivel wrench	40.00
2—15" combination wrenches	4.40
1—18" combination wrench	2.96
1—18" Trimo wrench	2.85
2—14" Trimo wrenches	3.85
2—24" Trimo wrenches	7.97
6—36" sledge hammer handles	1.76
2—16-lb. single pein sledge hammers	2.56
2—Long handled, round-point shovels	2.80
1—7-point hand saw	1.90
1—12" ratchet brace	2.50
1—Set ¼" to 1" auger bits	3.80
1—Spirit level	1.25

1—24" carpenter's steel square	1.25
4—1" hand cold chisels	1.50
2—1" Cape chisels	1.00
1—Pair 20" S. L. blacksmith's tongs	.88
1—Pair 20" C. L. blacksmith's tongs	.88
2—Germantown rig builder's derrick hatchets	3.00
1—Single bit axe and handle	2.50
1—3-lb. ball pein hammer	4.50
1—No. 1A Toledo stock and die threads 1" to 2" pipe	24.00
1—No. 2 Barnes three-wheel pipe cutter	4.00
6—Extra wheeels for above	1.20
1—No. 7 Little Giant screw plate set	34.00
1—No. 3 combination bench and pipe vise	50.00
1—10" iron snatch block	12.00
1—No. 9 Star hack saw frame	2.60
1—Dozen Star hack saw blades	1.40
1—⅞"x18"x36" ship auger	3.75
1—1"x18"x36" ship auger	4.50
1—No. 2 Pratts patent auger handle	2.25
100—Lbs. No. 4 babbitt	22.00
1—6" babbitt ladle	1.50
25—Lbs. 1-16" red rubber sheet packing	15.00
6—12" M. B. files	3.00
6—14" F. B. files	5.20
6—14" half round files	6.45
6—6" S. T. files	1.40
24—5" hay fork pullies	19.20
2—4-lb. hot splitting chisels	2.60
2—24" chisel handles	1.00
2—16-lb. wedge-point crow bars	5.00
1—100' Rival steel tape	7.50
1—3" elliptic flue cleaner	2.70
2—No. 4 zinc oilers	2.30
1—100-lb. bale of white waste	25.00
4—5-lb. cans cup grease	4.00
1—50-lb. can common tallow	10.00
1—Bbl. steam cylinder oil	25.00
1—No. 33 portable blacksmith forge	36.00
600—Lbs. blacksmith coal	9.00
30—Feet ⅜" link log chain	10.00
1—12" telegraph wheel	1.00
1—150' telegraph cord	.75
1—No. 14 Bel punch	.75
3—Pairs 12" belt clamps	3.30
80—Feet ⅜" pipe for reverse lever	4.50
24—2" malleable ells	4.60
24—1" malleable ells	8.65

24—2" malleable tees	10.04
24—1" malleable tees	10.04
36—2" assorted nipples	6.40
36—1" assorted nipples	3.0[illegible]
12—½" assorted nipples	1.33
12—2" plugs	1.58
12—Each 2", 1" and ½" lip unions	40.95
6—2"x1" bushings	.56
6—2" O. C. standard flange unions	10.56
12—Each 2", 1" and ½" globe valves	89.81
6—Each 2" and 1" stop cocks	25.08
400—Feet 2" 1200-lb. test line pipe	88.00
200—Feet 1" black merchant pipe	24.96
100—Feet ½" black merchant pipe	6.52
1—Set never slips	7.00
Grand total cost complete string tools	$16,604.54

Drilling North Texas formations.—The Pennsylvanian formations of North Texas present no difficult problems in drilling. Very few cavey formations are encountered as long as the hole can be kept dry. When water sands are encountered it usually becomes necessary to run pipe or underream the last string of pipe in the hole through the water sand. A surprising amount of open hole can be carried as long as water is kept off of the sides of the hole. Near Mineral Wells, in Palo Pinto County, Owens and Wilson drilled their No. 1 Oaks to 4,550 feet with only 2,200 feet of 6⅝-inch casing in the hole, making a total of 2,350 feet of open hole. This example is rather exceptional but it is considered no feat at all in this area to have 1000 to 1500 feet of open hole ahead of the pipe.

When water sands are encountered they are usually drilled through and to the first lime shell beyond. The casing is then landed on this lime shell. The water is usually shut off with but very little trouble when the pipe is landed in this manner. It is very remarkable to a person coming from California to see the ease with which water is shut off in Texas. Cementing and mudding-in of water sands seem to be entirely unnecessary.

It is customary, when the depth to the producing sand is known, to land a string of casing immediately above the point where the production is expected. This string of pipe cases off all of the open hole above the sand and it is very desirable to do this whenever possible.

The tendency in North Texas up until lately has been to run entirely too long strings of light-weight pipe in the wells. As a consequence there is quite a good deal of collapsed pipe, and collapsed pipe in a hole presents the very worst type of fishing job.

With an idea of showing just how long a string of any size or weight casing can be run in a well the following table of collapsible pressures is given:

TABLE SHOWING THE COLLAPSING PRESSURE OF LAP-WELDED STEEL CASING

Size inches	Weight per ft. pounds	Inside diameter inches	Outside diameter inches	Thickness inches	Collapsing pressure lbs. sq. in.	Equivalent water column in ft.	Using safety factor 2
4½	15.0	4.500	5.000	0.250	2944	6790	3395
5 3-16	**17.0**	**4.892**	**5.500**	**0.304**	**3404**	**7840**	**3920**
5 3-16	20.0	4.780	5.500	0.360	4285	9870	4935
5⅝	20.0	5.370	6.000	0.315	3160	7280	3640
6¼	20.0	6.000	6.625	0.312	2704	6230	3115
	26.0	5.846	6.625	0.390	3717	8560	4280
	28.0	5.775	6.625	0.425	4167	9600	4800
6⅝	20.0	6.437	7.000	0.281	2096	4830	2415
	24.0	**6.334**	**7.000**	**0.333**	**2741**	**6320**	**3160**
	26.0	6.312	7.000	0.344	2867	6600	3300
	28.0	6.220	7.000	0.390	3440	7930	3965
7⅝	26.0	7.390	8.000	0.305	1914	4410	2205
8¼	28.0	8.015	8.625	0.305	1680	3870	1935
	32.0	**7.935**	**8.625**	**0.345**	**2080**	**4790**	**2395**
	36.0	7.875	8.625	0.375	2383	5490	2745
	38.0	7.765	8.625	0.430	2928	6750	3375
	43.0	7.625	8.625	0.500	3638	8380	4190
9⅝	33.0	9.500	10.000	0.250	780	1800	900
10	**40.0**	**10.000**	**10.750**	**0.375**	**1638**	**3770**	**1885**
	48.0	9.850	10.750	0.450	2234	5150	2575
	54.0	9.750	10.750	0.500	2643	6090	3045
11⅝	40.0	11.437	12.000	0.281	641	1475	737
12½	40.0	12.500	13.000	0.250	402	927	463
	45.0	12.360	13.000	0.320	745	1717	858
	50.0	**12.250**	**13.000**	**0.375**	**1109**	**2560**	**1280**
13½	50.0	13.250	14.000	0.375	936	2160	1080
15½	51.3	15.416	16.000	0.292	314	724	362

Note—The above table worked out on the following formula:
Where:

$$P=86670\frac{t}{d}-1386$$ =Collapsing pressure in pounds per square inch.

t = Thickness.
d = Outside diameter.

the size of pipe in **bold faced type** in the above table are the sizes

and weights most commonly used in North Texas. From this table the column entitled "using a safety factor of 2" is the one that should be used in figuring the length of a string of pipe that can be run to shut off water. The writer has seen this table tested out in quite a few instances. For example, using a safety factor of 2 for 6⅝ inch, 24-pound pipe it will be seen that 3165 feet is the maximum amount that can be run without collapsing. An instance is known where 3760 feet of this casing was run in a hole full of water in order to make a shut-off, and when the hole was bailed down, the casing collapsed at 3195 feet, just 30 feet below the calculated depth.

Recovering pipe from abandoned holes in North Texas is a relatively easy matter. It is quite a common thing to recover all of the casing. In producing wells it is customary to leave only the two smaller strings of casing in the hole and all of the larger pipe is removed. These larger strings of casing are usually removed before the well is drilled in.

Pulling casing. In pulling casing great care should be exercised to see that too much strain is not put on the pipe suddenly. If this is done all of the tension is thrown into the top few joints and the pipe will part. If a very gradual tension is put on the casing elevators and the strain allowed to equalize throughout the length of the string of casing it will usually come. If it does not come this way a considerable amount of tension can be taken, the slips set in the spider, and the strain left on for several hours. This usually loosens the pipe in the stuck place. Judgment has to be exercised to know how much tension to take in a string of pipe. Almost all of the old experienced pipe pullers go by the rule that a string of pipe will give one inch, in tension, for every hundred feet of length. In other words, for a string of pipe 2000 feet long it will be found that the casing elevators will rise above the derrick floor 20 inches before the casing shoe will leave bottom. This simple rule is used often to tell at just what point in the hole a string of pipe is frozen. It is customary if only 10 inches of "tension" is gotten to conclude that the pipe is frozen at 1000 feet. This information proves very valuable at times.

Very few people realize the enormous pulling power of the ordinary chain driven calf-wheel-pipe-handling device such as is in common use in North Texas, using an ordinary 12x12-inch drilling engine which is supposed to develop about 30 h. p. with 125

pounds steam pressure. These engines have a 30-inch pulley which drives a 10-foot bandwheel, hence the engine's power at the bandwheel is multiplied four times. This bandwheel has on the same shaft with it a 30-inch sprocket for No. 1030 chain. This sprocket drives an 84-inch diameter sprocket on the calf wheel which multiplies the power two times. The casing line is strung through a four-shieve block affording 9 lines, which multiplies this last power by nine. Hence the power as developed on the 30-inch pulley of the steam engine is multiplied as follows:

$$4 \times 2 \times 9 \times 2 = 144 \text{ times}$$

If a string of pipe cannot be pulled by ordinary methods, that is, by making a straight pull on it from the calf wheel and using a casing block having 4 shieves, hydraulic jacks are usually inserted under the spider. The jacks usually lift 100 tons each. The tension in the pipe is taken up with the jacks and a trip spear is then run down inside the casing on the tools and a hold taken at the point where the pipe is believed to be frozen. The tools are then started with a "jar-up" motion and the casing is lifted with the jacks. For doing work of this kind it is well to have a rather deep cellar so that the jacks and spider can be kept below the level of the derrick floor. The above outlined procedure will usually free an ordinary string of frozen casing. If it does not it may be that the spear is jarring at the wrong place and the hold is broken and the spear reset at some other point in the casing and the operation repeated.

The drilling of the well.—The first drilling operation on a well in North Texas is known as "spudding." The common practice at the present time is to "spud-in" with a wire line of either ¾ or ⅞-inch diameter using about 100 feet of 2¼-inch manila cable for a jerk line connecting the crank arm with the spudding line. Spudding with a wire line was formerly considered hard on a rig but with the heavy rigs now being used this is not noticed. Spudding with a wire line has been made almost necessary of late due to the scarcity and high price of manila line, and one sees very little of the manila line in use for drilling purposes.

It is customary to "spud" in North Texas for a considerable depth, sometimes as deep as 400 feet. Then the tools are "hitched-on" to the temper screw and the regular drilling operation starts with the walking beam furnishing the drilling motion. Some op-

erators do not use drilling jars in the big hole unless the formation seems to "mud" the tools up, causing them to stick. Almost all of the operators use a swivel socket of some make with the wire line.

At the present time almost all of the operators are using a ⅞-inch diameter steel drilling line made up of 6 strands of 19 wires each with a hemp center. This size is used until the 8-inch hole is reached and by some it is used until the well is finished. Some operators, of late, have started using a ¾-inch diameter 6x19 line in 8-inch and smaller hole. This effects quite a saving in cost and at the same time better drilling progress is made as the line has more spring with the light tools used in the small hole. Hence using the smaller line the driller is better able to tell how the tools are working.

There are only three kinds of formations encountered in North Texas above the black shale of the Bend. They are: gray lime, blue shale, and sand. The lime and shale drill very nicely but the sands give trouble. In the first place the sharp sand cuts the bits and they soon get out of gauge. Unless the bits are taken off frequently and dressed "tight hole" results and when the casing is run it usually hangs up in these places. "Flat" and crooked hole is often made in water sands. When the pipe is picked up to underream through these sands it will be found that the sand cuts the cutting edge off of the under-reamer lugs very fast. By dressing the lugs out just as far as possible and still have them go down the pipe and being extremely careful with the temper it will be found that less dressing will be necessary and more progress can be made.

Dressing under-reamer cutters.—The Union Tool Company gives the following instructions relative to the proper dressing and tempering of under-reamer cutters:

To dress cutters.—Bring slowly to an orange heat which is about 2000 degrees Fahrenheit and do not forge below a red heat, plainly visible in daylight. The heel of every cutter in dressing must be kept parallel with the cutting edge or in other words, have the bottom of the cutter straight across, which is the shape or form of all new cutters. If cutting edge is stove back of the heel the cutters will wedge on the tongue crushing same, the result being efficiency greatly decreased. After dressing cutters allow them to cool to hand warm before reheating for tempering.

To temper cutters.—Heat slowly and evenly to 1450 or 1500 degrees Fahrenheit, which is indicated by a cherry red, then dip about ½ inch of the cutting edge into clear water stirring the cutter around so as to keep the water in close contact with its surface. Allow the cutter to remain

until the cutting edge is cool then quickly dip the cutter half way into water to prevent a check forming between the relatively hot and cold parts. Polish the cutting edge to observe the color, and when it has run down to a straw color on the edge, set the cutter in about 1 inch of water or a bath of mud and allow to cool slowly.

It is becoming common practice in California to take under-reamer cutters after they have been dressed and melt some cast iron on to the cutting edge with a blow torch. It is found that the cutters will go quite a good deal longer this way before they need dressing. Texas operators should adopt this simple method of treating the cutting edge in order to get more service out of their cutters, especially in view of the fact that a set of cutters for a 10-inch Union under-reamer now cost in the neighborhood of $90.00.

Very little 12½-inch or larger pipe is under-reamed in North Texas. The 10-inch and 8¼-inch are under-reamed usually with Union or Wilson under-reamers, while the favorite under-reamer for under-reaming 6⅝-inch casing is the Swan. One should be very careful to see that the cutters for these under-reamers are for the exact weight of pipe which is to be underreamed.

Drilling in the black lime.—The drilling in the bottom of most of the wells drilled in North Texas is in the black lime formation. At Ranger a couple hundred feet of black lime is usually encountered. Wells drilled in other localities have encountered as much as 750 feet of it. The hardness of this formation coupled with the difficulty of making hole in it is the talk of North Texas. However, one keen observer has remarked that when the companies start to paying the contractors by the foot to drill it instead of by the day, as at present, this will probably "soften the black lime up considerably."

One well with which the writer is very familiar drilled 600 feet of black shale and 750 feet of black lime in 50 days drilling time. The black lime in this well was extremely hard in places. This well was drilled with company tools.

Advantages of accurate samples.—In North Texas drillers are prone to disagree as to the proper name for formations in which they are drilling. For instance, one driller will say he is in gray sandy lime and the driller working on the other tour will log the same formation as gray limey sand. One will log black lime where another will log black slate or chert. It is quite common for one

driller to log a shale as blue where another driller would log its color as black. This leads to quite a difference in appearance of logs of wells drilled close together and geologists and others engaged in working out sub-surface conditions are often misled. The only way in which to settle questions of this kind is to require that samples be furnished every few feet, or at least for every change in formation. Contractors will invariably offer strenuous objection to furnishing samples and some drillers do not like to slow down the work for the length of time necessary to get the samples. However, to companies drilling outside of the proven areas it is absolutely essential that these samples should be kept and more and more stress is being laid on this as time goes on. Quite often the trouble and expense of drilling another well may be saved by having an accurate sample of each of the sands drilled through. Sand samples also tell one as to whether it would pay to shoot a well and as to how heavy a charge of nitro-glycerine will be needed.

Possibly the greatest objection to the contract system of drilling lies in this one feature. A contractor who is getting so much per foot for making hole is going to slight any operation which tends to delay the drilling progress. On isolated tests where shut-downs and fishing jobs are extremely numerous (locations on which samples are always particularly desired) this will be particularly true.

COST OF DRILLING WELLS IN NORTH TEXAS

The cost of completing a test in North Texas varies with the area in which the test is being drilled, the depth to the producing sand, the amount of under-reaming which has to be done, the amount of black lime that has to be drilled through and numerous other things.

Operating companies find that they save but little in the long run by operating their own tools, and for this reason the contract price of drilling is used as a basis in making up estimates of cost. Below are given a few examples of detailed estimates of cost of completed wells, as of June, 1919:

Cost of a Well At Ranger.

1—84'x22' sway braced standard rig with 6-inch Ideal rig irons...		$ 4,500.00
Drilling—		
3200 feet at $3 per foot	$9,600.00	
200 feet black lime at $10	2,000.00	
15 days under-reaming at $100	1,500.00	
5 days shut down at $70	350.00—	13,450.00

Cost of a Well At Ranger.—Continued.

Fuel and water—		
60 days gas at $15	$ 900.00	
Water service	300.00—	1,200.00
Freight and hauling		1,000.00
Tanks, flow lines, etc.		3,000.00
Casing—		
350 feet of 15½-inch 70-pound casing	$1,862.00	
800 feet of 12½-inch 50-pound casing	2,648.00	
1400 feet of 10-inch 40-pound casing	3,430.00	
2000 feet of 8¼-inch 32-pound casing	3,960.00	
3200 feet of 6⅝-inch 24-pound casing	4,576.00—	16,476.00
200 quart shot of nitro-glycerine		920.00
Add 10 per cent for unforseen expenses		4,055.00
GRAND TOTAL		$44,601.00
Less probable salvage for producing well		6,352.00
Net cost of producing well		38,249.00
Less additional salvage if dry hole		9,329.00
Net cost of dry hole		$28,420.00

Estimated Cost of Well In Desdemona Field (1919).

1—84'x22' sway braced standard rig with 6-inch Ideal rig irons		$ 4,800.00
Drilling—		
2700 feet at $4 per foot	$10,800.00	
150 feet black lime at $10	1,500.00	
10 days shut down at $75	750.00—	13,050.00
Fuel and water—		
50 days gas at $15	$ 750.00	
Water service	400.00—	1,150.00
Freight and hauling		1,150.00
Tanks, flow lines, etc.		3,000.00
Casing—		
800 feet 12½-inch 50-pound casing	$ 2,648.00	
1400 feet 10-inch 40-pound casing	3,430.00	
2000 feet 8¼-inch 32-pound casing	3,960.00	
2700 feet 6⅝-inch 24-pound casing	3,861.00—	13,899.00
1—200 quart shot of nitro-glycerine		920.00
Add 10 per cent for unforseen expenses		3,842.00
GRAND TOTAL		$42,261.00
Less probable salvage for producing well		4,863.00
Net cost of producing well		37,398.00
Less additional salvage if dry hole		9,257.00
Net loss if dry hole		$28,141.00

Estimated Cost of Well in the Breckenridge Field (1919).

1—84'x22' sway braced standard rig with 6-inch Ideal rig irons, California pattern		$ 5,100.00
Drilling—		
3200 feet drilling at $5 per foot	$16,000.00	
25 days under-reaming at $100	2,500.00	
15 days shut down at $75	1,125.00—	19,625.00
Fuel and water—		
80 days gas at $15	$ 1,200.00	
Water service	650.00—	1,850.00
Freight and hauling		2,700.00
Tanks, flow lines, etc.		3,000.00
Casing—		
350 feet 15½-inch 70-pound casing	$ 1,862.00	
800 feet 12½-inch 50-pound casing	2,648.00	
1400 feet 10-inch 40-pound casing	3,430.00	
2200 feet 8¼-inch 32-pound casing	4,356.00	
3100 feet 6⅝-inch 24-pound casing	4,433.00—	16,729.00
200 quart shot of nitro-glycerine		920.00
Add 10 per cent for unforseen expenses		4,920.00
GRAND TOTAL		$54,844.00
Less probable salvage for producing well		6,352.00
Net cost of producing well		48,492.00
Less additional salvage if dry hole		10,031.00
Net loss if dry hole		$38,461.00

Estimated Cost of Well in the Caddo Field (1919).

1—84'x22' sway braced, standard rig with 6-inch Ideal rig irons, California pattern		$ 5,000.00
Drilling—		
3200 feet drilling at $4.50 per foot	$14,400.00	
12 days under-reaming at $100	1,200.00	
12 days shut down at $75.00	900.00—	16,500.00
Fuel and water—		
60 days gas at $15	900.00	
Water service	500.00—	1,400.00
Freight and hauling		3,400.00
Tanks, flow lines, etc.		3,000.00
Casing—		
350 feet 15½-inch 70-pound casing	$ 1,862.00	
800 feet 12½-inch 50-pound casing	2,648.00	
1400 feet 10-inch 40-pound casing	3,430.00	
2200 feet 8¼-inch 32-pound casing	4,356.00	
3100 feet 6⅝-inch 24-pound casing	4,433.00—	16,720.00

Estimated Cost of Well in the Caddo Field (1919).—Continued.

1—200 quart shot of nitro-glycerine		920.00
Add 10 per cent for unforseen expenses		4,695.00
GRAND TOTAL		$51,644.00
Less probable salvage for producing well		6,352.00
Net cost of producing well		45,292.00
Less additional salvage if dry hole		10,031.00
Net loss if dry hole		$35,261.00

Estimated Cost of Well In Northern Stephens County or Southern Young County (1919).

1—84'x22' sway braced, standard rig with 6-inch Ideal rig irons, California pattern		$ 4,700.00
Drilling—		
3400 feet drilling at $5 per foot	$17,000.00	
600 feet black lime at $10 per foot	6,000.00	
40 days under-reaming at $100	4,000.00	
30 days shut down at $75	2,250.00—	29,250.00
Fuel and water—		
1500 cords wood at $5	$ 7,500.00	
Water service	1,000.00—	8,500.00
Freight and hauling		2,000.00
Tanks, flow lines, etc		3,000.00
Casing—		
300 feet 20-inch 90-pound casing	$ 2,160.00	
700 feet 15½-inch 70-pound casing	3,724.00	
1200 feet 12½-inch 50-pound casing	3,972.00	
1700 feet 10-inch 40-pound casing	4,165.00	
2400 feet 8¼-inch 32-pound casing	4,752.00	
3100 feet 6⅝-inch 24-pound casing	4,433.00	
4000 feet 5 3-16-inch 17-pound casing	4,080.00—	27,286.00
1—200 quart shot of nitro-glycerine		920.00
Add 10 per cent for unforseen expenses		7,566.00
GRAND TOTAL		$83,222.00
Less estimated salvage for producing well		15,217.00
Net cost of producing well		68,005.00
Less additional salvage if dry hole		10,612.00
Net loss if dry hole		$57,393.00

Note—This estimate will be found fairly accurate for wells drilled in eastern Callahan and Shackleford Counties.

Estimated Cost of Well In Palo Pinto County.
(Mineral Wells Area. 1919).

1—84'x22' sway braced, standard rig with 6-inch Ideal rig irons, California pattern		$ 4,500.00
Drilling—		
3800 feet of drilling at $3.50	$13,300.00	
700 feet black lime at $10 per foot	7,000.00	
20 days shut down at $75	1,500.00—	21,800.00
Fuel and water—		
90 days gas at $15	1,350.00	
Water service	1,000.00—	2,350.00
Tanks, flow lines, etc.		3,000.00
Freight and hauling		1,600.00
Casing—		
350 feet 15½-inch 70-pound casing	$ 1,862.00	
800 feet 12½-inch 50-pound casing	2,648.00	
1100 feet 10-inch 40-pound casing	2,695.00	
2800 feet 8¼-inch 32-pound casing	5,344.00	
3800 feet 6⅝-inch 26-pound casing	6,460.00	
600 feet 5 3-16-inch 17-pound casing	612.00—	19,621.00
1—200 quart shot of nitro-glycerine		920.00
10 per cent for unforseen expenses		5,379.00
GRAND TOTAL		59,170.00
Less estimated salvage for producing well		5,764.00
Net cost of producing well		53,406.00
Additional salvage for dry hole		13,933.00
Net loss if dry hole		$39,473.00

The value of estimates of cost of wells.—From the foregoing tables of cost it will be seen that there are several items of cost which will vary greatly for individual wells. For instance, where operations are being carried on with company tools instead of by contract the cost of drilling may be considerably under or over the contract price, depending on the efficiency of the work and the luck you have in avoiding fishing jobs. Also, depending on the location and the weather, the cost of hauling pipe will vary considerably for individual wells. The North Texas roads are the worst imaginable in wet weather and in making up estimates the worst of conditions must be taken into account.

Pipe jobs and fishing operations will run the cost of wells up enormously. For instance, in Young County where a producing

vell should not cost over $68,000, according to the estimate, there ıre several wells as yet not completed (but all below 4000 feet in lepth), which have cost their owners upwards of $100,000 apiece. No estimates can take into consideration the most extreme conlitions.

It is hoped that these figures will be of value principally in ;iving the public a general idea of the cost of operating in North Texas. Of course, all of the larger companies keep detailed cost heets showing the cost of drilling wells but these figures are very eldom given to the public.

SHOOTING OF NORTH TEXAS WELLS.

It is getting to be standard practice in North Texas to shoot vells drilled into the black lime whether or not they show for anyhing when drilled. The No. 1 Carey of the Mid-Kansas Oil & Gas Company at Caddo was rated as a very small well until it was hot with 400 quarts of nitro-glycerine. After the shot it produced s high as 12,870 barrels per day. The No. 1 Manning well of the Sinclair Gulf Company at Caddo was reported as absolutely dry vhen drilled in. This well was shot with 400 quarts of nitro-;lycerine, using 4½-inch shells and it started off at 400 barrels per ay.

The extensive shooting of wells in this area has created such a emand for nitro-glycerine that the companies are kept busy filling rders. At present there are five nitro-glycerine companies engaged in this work. The standard price for nitro-glycerine shots s as follows (1919):

10 quarts and under	$100.00
20 quarts	125.00
30 quarts	170.00
40 quarts	204.00
50 quarts	250.00
60 quarts	296.00
80 quarts	388.00
100 quarts and over, per quart	4.60
Minimum charge for 10 quarts and under	100.00
Electric wire, per foot	.05

Below is given a tabulation showing the amount of nitro-glycerine required to shoot any amount of hole, depending on the ze of shell used:

TOTAL LENGTH OF 20-QUART SHELLS.
(Figured to the nearest half foot.)

Diam. Ins.	1 Shell	2	3	4	5	6	7	8	9	10
2	31′ 6″	63	94.5	126	157.5	189	220.5	252	283.5	315
2½	20′ 1″	40	60.5	80.5	100.5	120.5	140.5	160.5	181	201
3	12′ 9″	27.5	41	55	69	82.5	96.5	110	124	137.5
3½	10′ 2″	20.5	30.5	40.5	51	61	71	81.5	91.5	101.5
4	7′ 11″	16	24	31.5	39.5	47.5	55.5	63.5	71.5	79
4¼	7′ 9″	14	21	28	35	42	49	56.5	63.5	71
4½	6′ 4″	12.5	19	25.5	31.5	38	44.5	50.5	57	63.5
4⅞	5′ 5″	11	16.5	21.5	27	32.5	38	43.5	49	54
5	5′ 2″	10.5	15.5	20.5	26	31	36	41.5	46.5	51.5
5¼	4′ 9″	9.5	14.5	19	24	28.5	33.5	38	43	47.5
5½	4′ 4″	8.5	13	17.5	21.5	26	30.5	34.5	39	43.5
5¾	4′ 1.7″	8	12	16.5	20.5	25	28.5	33	37	41
6¼	3′ 6.5″	7	10.5	14	17.5	21	25	28	32	35.5
7	2′ 11.6″	6	9	12	15	18	21.5	24.5	27.5	30.5

It is customary, when desiring to make a very heavy shot in the black lime, to use a 5-inch diameter shell extending for the distance representing the thickness of the lime or sand it is desired to shoot. Some small shots using 2-inch and 3-inch diameter shells are used, but it is the opinion of competent shooters that operators waste their money in using shells of this small diameter.

It is impossible to compute with any accuracy the amount of force expended underground by shots of different sizes, and operators are governed more by custom than anything else in deciding as to the best method of shooting and the amount of charge. Some operators shoot with a cushion of about 100 feet of water on top of the shot, while others prefer upwards of 1000 feet of water on top of the explosive. There are quite a few instances known where shots have been set off with the hole completely filled with water. Very good success is gotten in this manner.

In shooting, the lowermost string of casing should be pulled up so that the bottom of the casing is at least 400 feet above the top of the water placed above the shot. It has been found that if the water cushion is allowed to extend up into the casing, the force of the shot will burst the casing at a point opposite the level of the water. The only exception to this is where the hole is completely filled with water, and in this case the water simply "boils" over when the shot goes off. For small shots of around 100 quarts it may not be necessary to raise the casing further than 100 feet above the top of the water cushion; and for shots of 500 quarts or over it is customary to remove the inner string of casing entirely.

Nitro-glycerine shots exploded due to earth temperature.—The ordinary method of setting off a charge of nitro-glycerine is with a "go devil" squib or bumper squib. Instances are known in North

Texas where considerable difficulty has arisen in trying to get shots exploded. The nitro-glycerine companies made a very interesting discovery in connection with the shooting of North Texas deep wells which have been drilled into the black lime. They have found that in any well over 3200 feet deep the temperature of the earth at that depth is sufficient to cause the nitro-glycerine to explode spontaneously. Quite a few instances are known where wells have "shot themselves." The length of time which it takes a shot to go off spontaneously varies with the glycerine used and with the depth of the hole. Wells have been known to "shoot themselves" at Ranger in 72 hours, and the shortest time known at Breckenridge has been 54 hours. The No. 1 Ledbetter well of the Sinclair Gulf Company at Caddo had a charge of 400 quarts of nitro-glycerine exploded spontaneously after the shooter had made quite a few unsuccessful attempts to explode the charge with a squib. The deepest well ever shot with nitro-glycerine in North Texas, namely, No. 1 Seaman of the Roxana Petroleum Company, in Palo Pinto County, had a charge of 380 quarts, placed 4100 to 4250 feet, exploded spontaneously due to earth temperature in about 30 hours.

Notes on Spontaneous Explosions of Nitro-glycerine in Oil and Gas Wells, Stephens, Palo Pinto and Young Counties, North Texas[1]

Introduction.—The spontaneous explosion of charges of nitro-glycerine placed in deep wells situated in parts of the Ranger and Caddo fields of North Texas has aroused considerable inquiry among operators and others as to the probable agency, or combination of conditions, which causes the explosion.

The method now followed, under certain physical conditions of a well, of setting a charge of nitro-glycerine and allowing it to explode spontaneously, was discovered locally by accident. In certain deep wells where formations overlying productive strata cave upon withdrawal of casing, it has been the practice to fire the shot electrically. In some of these operations the electric wires are broken or the firing system is otherwise deranged by pulling casing or the caving of hole prior to the time for firing. Such accidents make it necessary for the driller carefully to clean cavings out of the hole to a depth close to the top of the charge, after which in the normal practice an attempt is made to fire the charge by dropping a "jack-squib," fitted with a fuse and detonator, down the well. Mr. R. L. Fowler, production manager for the Pierce Oil Corporation, reports that a delayed shot was thus successfully fired through four feet of caved material lying on top of the nitroglycerine shells.

When a shot destined to be fired electrically fails, because of the above-

[1]R. E. Collom, Petroleum Technologist, Bureau of Mines.

mentioned accidental conditions to the electric firing system, much time is required for the driller to run casing into the hole and clean out caved material. It was during the time of such uncompleted operations that the spontaneous explosions first noted took place. Having noted these spontaneous explosions, the well shooters now intentionally place a charge in deep holes, which because of probable caves would otherwise have to be fired electrically, and wait for the charge to go off. No detonators are placed with the charge.

Purpose for which nitro-glycerine is used in oil wells.—Before discussing the probable causes of spontaneous explosions, it may be well to describe briefly the several purposes and methods of using nitro-glycerine in oil and gas wells.

Casing and tubing shots.—A small charge of nitro-glycerine is used when necessary to shoot a string of casing in two. The nitro-glycerine is run inside the casing in a "casing squib." The casing squib is fitted internally with a firing tube which contains two percussion caps set on an iron pin. The pin is in direct contact with a metal rod known as the firing head. The squib is lowered to the desired position in the casing. The antennat projecting upward from the bottom of the squib become caught in the nearest collar joint as the squib is raised up and down in the casing near the desired depth. It is desirable to disrupt the casing at a collar. When in position a heavy weight slides down the iron wire, upon which the squib is suspended, and which is also connected to the firing head, and the shot is fired.

A similar method is used with a tubing squib for shooting off tubing.

Shooting for production.—In shooting for production, the nitro-glycerine charge is run into the hole in shells to the desired depth. The shells are made of tinned sheet metal. The detonator for firing is a "squib" of several varieties, but run separately from the shells. The shells are shaped at the ends according to the work desired of the nitro-glycerine. The single-shell charge will be used in a shell pointed at one end and having a bail at the other end.

The shells are frequently assembled with small tubes of the same material, known as anchors, either connecting several shells at certain distances apart, or a string of shells, with stub anchors between, will have an anchor on the bottom to keep it a certain distance up from the bottom of the hole. When the shells are spaced with anchors, the anchors contain nitro-glycerine also, and are called "loaded" anchors. The loaded anchor is supposed to span the gap across a shale break or other supposedly non-producing material, so that the main force of the shot can be exerted where it will do the most good. The anchor placed at the bottom of a shell is not loaded and is called a "common" anchor. Various kinds of anchor "tips" are used as fittings for connecting shells and anchors.

The filling end of the shell is fitted with a downward pointing cone-shaped diaphragm. This diaphragm is perforated with several holes. When the shells are assembled, according to whatever fashion may be desired, they are lowered into the hole until the filling end of the shell is only a short distance above the floor of the derrick. The nitro-glycerine is then

poured into the shells from cans until they are filled within an inch or two of the top.

Amount of nitro-glycerine used.—The amount of nitro-glycerine used in shooting for production is gauged by the thickness of supposed oil-bearing formations and diameters of hole. It is not unusual practice to load the hole with all the nitro-glycerine that can be held in the largest diameter of shell that will pass into the hole. The operator advises the shooter that he wants to shoot formations between certain depths, or a sand of a stated thickness, in a certain diameter hole, and the shooter fills the order. For general use the shells are made up in 3, 5 and 7-inch sizes. Other sizes are also made. The sizes mentioned are of several lengths and hold respectively 10, 20 and 30 quarts.

Methods of firing.—After the charge is presumably lowered to the place desired, it is fired with a squib. The squibs commonly used are called "jack squib," "bumper squib," or "electric squib."

The jack squib and bumper squib are suitable for use in open hole where there is no danger of caving formations, or where it is not necessary to remove casing because of the proximity to formations to be shot.

The jack squib is a tinned tube about 1½ inches in diameter and 3 feet long. Ribs of the same metal, of rectangular cross-sections, are soldered along the outside of the tube to reinforce it and protect it against wear as it drops down the hole. The squib has a cast-iron tip which reinforces the end and keeps the squib from hanging up on some projection on side of the hole.

A tube about ⅜ inch in diameter, containing nitro-glycerine and detonator on the end of a fuse, is packed in sand in the center of the squib. The fuse, of a desired length, is wrapped around the tube and the end to be lighted passes out of the squip through a small nipple soldered at an acute angle to the side of the squib. This squib is dropped down the hole upon the charge to be fired.

The "bumper squib" is a tube about the same dimensions as the "jack squib." The bumper squib is discharged with a detonator and a firing head. The inner tube of nitro-glycerine is rigged to carry a firing pin and percussion caps. The firing pin extends through the top end of the squib and a three-legged guide. The top of the firing pin is weighted. When the bumper squib strikes an obstacle, the momentum of the weighted firing head is sufficient to explode the caps.

The jack squib is more suitable for firing through a considerable column of fluid. It carries a burning fuse, headed with a detonator, and of course, while the fuse is burning, will drop through several hundred feet of fluid until it comes in contact with the main charge. It is then in position to explode the nitro-glycerine when the fuse burns into the detonator within the "jack squib." Shooters prefer to use "jack squibs" for firing a charge, rather than squibs with a firing head.

The electric squib is similar in makeup to the small casing squib. It has no antennae, however. The electric squib is lowered into the hole to the top of the charge with about 14-gauge insulated copper wire. It is filled

with nitro-glycerine and contains an electrically sensitive detonator. The electric squib is usually used where removal of casing permits formations to cave on top of the charge. Each joint of casing has to be stripped off of the wire as the casing is pulled out and unscrewed. This work and the caves have already been mentioned as the direct cause of the "discovery" of the so-called spontaneous explosions of nitro-glycerine.

The following are examples of the thickness of strata through which a charge of nitro-glycerine is distributed for shooting. Details of spontaneous shots are discussed later.

Depths of nitro-glycerine shots in oil wells between Ranger and Caddo fields, Texas.—

Company	Lease	Well No.	Quantity qts.	Depth in feet from	Depth in feet to	Thickness in feet	How fired
Sinclair Oil Co.	Satterfield	2	300	3338	3210	128	Electrically
Palo Pinto Oil Co.	Swenson	23	100	3481	3454	27	Electrically
Pierce Oil Corporation	Thomas	1	220	3143	3019	124	Electrically
Pierce Oil Corporation	Thomas	1	80	3299	3243	56	Electrically
Pierce Oil Corporation	Thomas	3	260	3151	3050	101	Electrically
Pierce Oil Corporation	Thomas	24	280	3210	3108	102	Spontaneously
Roxana Petroleum Co.	Seaman	1	320	4200	4100	100	Spontaneously

In the writer's opinion, the quantities of explosive used are in many instances excessive. Well shooters have not, as far as can be learned, made a scientific study of the quantity of nitro-glycerine necessary to shoot a hole properly. It is not unusual practice to load the hole with the largest diameter of shell that will pass into the hole.

The cause for the use of large quantities of explosives is readily understandable. The shooting companies manufacture their own nitro-glycerine. The oil operators have not the first inkling of the necessary amount of explosive to use, and, naturally, are not desirous of getting within observing distance of the hazardous proceeding. Oftentimes, though, shooting companies' revenues represent principally a sale of nitro-glycerine rather than a fee for shooting a well.

Most of the nitro-glycerine used for shooting wells in North Texas is made locally; that is, at plants 15 or 20 miles from the fields. The explosive is also hauled into Texas overland from Oklahoma.

There has been a great demand for nitro-glycerine in North Texas fields. This demand has probably caused carelessness in manufacture. Mr. W. P. Gage, of the Lone Star Gas Company, says that his men report that the glycerine now being used appears dirty or rusty as compared with the stock used in normal times.

Spontaneous explosions.—Mr. R. L. Fowler, general manager of the Pierce Oil Corporation, reports a spontaneous shot for its well No. 24, Thomas lease, Satterfield area, Stephens County.

"On February 13, 1920, 280 quarts of nitro-glycerine was set in the hole between depths of 3108 to 3210 feet, in black lime formation. The charge was set at 1:30 p. m., and exploded at 2:45 p. m., one hour and fifteen minutes. There was 150 feet of oil in the hole when shot. No detonator was used."

W. A. Snyder, expert driller of the Bureau of Mines, obtained the fol-

lowing information from Messrs. W. P. Gage and T. W. Sutherland, of the Lone Star Gas Company, in answer to interrogatories sent the writer by Dr. Charles E. Munroe, chairman of committee on explosives, National Research Council.

These gentlemen stated that practically all the shots in the Ranger-Caddo district are being fired by simply leaving them in the hole anywhere from 36 hours to 100 hours when they explode spontaneously.

Ordinarily shots in this district are placed, according to depths of holes, from 3000 to 3800 feet.

With respect to the amount of pressure that could accumulate on a torpedo in a 3000-foot hole, as much as 1600 feet of fluid (oil) was noted in a 6⅝-inch hole.

The Lone Star Gas Company representatives' experience showed that in the last two wells shot the charge in one well, depth 3157 feet, exploded after 91 hours, and in the other well, depth to top of charge 3600 feet, after 72 hours.

Temperatures.—Regarding temperatures, Mr. J. R. Suman advises that C. E. Van Ostrand, physicist with the United States Geological Survey, measured temperatures of well No. 1, Goode, of Roxana Petroleum Company, to a depth of 3200 feet and found a geothermal gradient of one degree for 47 feet. However, the well was later drilled to 4029 feet and just before encountering a half million cubic feet of gas at 4029 feet the cuttings were very hot. The temperature was estimated at 150 degrees Fahrenheit.

While drilling on well No. 1, Seaman, of Roxana Petroleum Company, mentioned above, the cuttings were so hot at 4535 feet that they could not be touched with the bare hands. This condition was also true for the tools on drawing them from the hole.

According to telegraphic advice from J. O. Lewis, chief petroleum technologist of the Bureau of Mines, the average temperature in Ranger field, Stephens County, is 131 degrees Fahrenheit at 3000 feet, with a geothermal gradient of one degree for each 47 feet increase in depth. These data were determined by Van Ostrand, and of course agree with the figures given above by Suman.

Pyritiferous material as a possible cause of high temperature.—Additional interrogatories of Dr. Charles E. Munroe were forwarded the writer, relative to the presence of pyritiferous material in the cuttings from strata in which spontaneous explosions occur.

These questions were brought up for discussion by the writer at the morning session of the American Association of Petroleum Geologists on May 19, 1920.

Three geologists stated that the black lime of the Bend series shows minute crystals of pyrite in thin sections under a microscope. Mr. J. R. Suman advised the writer that pyrite casts of fossils have also been brought up with the cuttings from these strata.

The limestone is interbedded with carbonaceous shale and the two kinds of rocks grade both vertically and laterally, one into the other, from well

to well. It is probable that in every case where a shot is placed, the shot is opposite both kinds of strata.

No definite data were obtainable as to whether or not pyrite predominated in the black lime or black carbonaceous shale.

The prevailing opinion in the discussion was that oxidation of the pyrite in the productive strata would cause rise of temperature. The quick rise of temperatures of holes in the Canal Zone, encountering pyritiferous material, was mentioned.

The objection was raised, however, that in practically all of the wells in Texas in which spontaneous explosions occur, a considerable head of fluid—either water or oil, or both—is standing in the hole and would therefore tend to prevent oxidation.

Conclusion.—From the above data the following suggestions and criticisms as to cause and effect are summarized:

1. In view of the fact that charges have exploded spontaneously both with and without detonators, this agency would seem to be removed as a possible factor of influence.

2. The nitro-glycerine shells are open at the top; external and internal pressures are equalized, and therefore, consideration of the pressure factor is eliminated.

It is concluded that spontaneous explosions are the result of the continued reactions of un-neutralized acids in the liquid, assisted by fairly high underground temperatures. Temperatures as already recorded may be sufficient to cause the explosive to gradually change chemically until detonation takes place.

However, there may be an increase of temperature beyond that normally recorded, due (1) to the oxidation of pyritiferous material, or (2) to the reaction taking place between the un-neutralized acid content of the nitro-glycerine with the minerals, including oil and water, in the limestone and shale rocks.

According to Snelling and Storm (Bureau of Mines Technological Paper No. 12), "Nitro-glycerine begins to decompose at temperatures as low as 50 degrees C. (122 degrees F.) to 60 degrees C. (140 degrees F.). At a temperature of 70 degrees C. (168 degrees F), nitro-glycerine of commercial quality evolves enough nitrous fumes to give a decided test with potassium-iodide starch paper at the expiration of fifteen to thirty minutes." They found that at 218 degrees C. (424.4 degrees F.) nitro-glycerine explodes.

Nitro-glycerine compounds can be exploded by ignition, which is the probable method in the spontaneous explosions already discussed. However, nitro-glycerine belongs to a group of explosives known as nitric esters, which in the words of Munroe and Hall (Bureau of Mines Bulletin No. 80), "Are more effectively exploded by detonation through the use of an exploding device of mercury fulminate or the hydronitrid of a metal or by the explosion of a contiguous mass of the same ester." By exploding with a detonator the molecules are literally "shaken apart," while in exploding by ignition the ordinary processes of oxidation ensue to a large extent,

though the rate of combustion may so increase that detonation eventually takes place.

It is quite probable that in the "spontaneous explosions" part of the nitro-glycerine is wasted, prior to exploding, by decomposition, and that the remainder is exploded through ignition in an incomplete manner.

One of the principal criticisms of the present system of shooting a long charge of nitro-glycerine in an oil well, is that a detonator can be placed by means of a squib, only at the upper end of the charge. Much more effective work could be produced from the explosive by detonators arranged at intervals through the mass and exploded simultaneously.

The practice of shooting wells spontaneously is perhaps convenient, but the hazards involved are great. The shooter, whose personal risks in his work are always enormous and varied, may not think there is any special hazard involved. However, the time of exploding is so variable that a serious element of risk, both to life and property, is injected.

It is already known that a number of wells have been lost in Texas fields because of premature explosions, in the upper part of the hole, and subsequent inability of the operator to clean out debris and drill back into the old hole below the premature shot. The feature of instability, because of impure manufacture, should not be played with nor should it be encouraged as an accessory feature simply because it facilitates the firing of shots which, with care in handling of casing, could be discharged electrically.

Nitro-glycerine, even when well made, is subject to decomposition at temperatures as low as 122 degrees Fahrenheit, and if the acid has not been completely removed it is subject to decomposition at lower temperatures. There is danger, therefore, of an explosion in a well before the charge has been completely set, which may injure the well or cause loss of life. Also, there are possibilities of accidents, during the summer months, from poorly made nitro-glycerine decomposing in the summer temperatures.

Drilling With Electric Power in Eldorado, Kansas, Field

That electricity is by far the cheapest power for drilling in oil fields near high-power transmission lines, is the conclusion of engineers of the Empire Gas & Fuel Company who carefully tabulated the results of the drilling of Stokes No. 27 in the Eldorado, Kansas, field. The actual saving over the use of steam for power was $3,655.20.

Perfect control assured.—"During the past, attempts have been made to use electric motor equipment for drilling deep wells," says Mr. Severson, head of the electrical engineering department, "but it has been only within the last year or two that much success has been attained. A number of wells have been drilled with electric motors in various parts of the world. The question of motor has been readily solved, but the perfect control necessary to satisfy all conditions in the drilling operation, has been difficult to obtain.

"Results obtained in the drilling of Stokes No. 27 and a subsequent well, show conclusively that a combination of motor and control apparatus has been perfected to a degree that causes even experienced drillers to say electric drilling equipment is superior to steam.

"Reports from operation give ample proof that the trial was satisfactory and successful."

"The maintenance of the electrical drilling equipment on Stokes No. 27 consisted principally of attention to the contact fingers and segments in the main controller, due to the fact that these parts become pitted by the arcing caused in reversing the motor, and prevent the fingers from making a good contact. This condition should not require the constant attention of an electrician, but could be handled by the regular inspector on his daily visit, and in the event of more serious trouble, the trouble man of the electrical department could be summoned.

"The driller and tool dresser became familiar enough with the electrical equipment during the test to be practically independent of outside assistance, so that electrical drilling equipment will not require the services of an extra man.

"On two or three occasions fuses were replaced, but at no time was there any serious electrical trouble. The principal delays incurred during the test were caused by rig equipment, and on one occasion by the shortage of 6⅝-inch casing. These delays were unavoidable.

"While the operations during the test covered a period of sixty days, the actual drilling was accomplished in thirty-four drilling days, and the only water required for the test was that used in the hole for mixing the drillings.

"The controllers were so arranged that they provided the motor eighty different speed variations. The controllers were operated by steel cable lines from levers on the 'headache' post. The weight of the motor was approximately two tons.

"The ammeter was located in the derrick close to the 'headache' post, and showed the driller the amount of power he was using. During drilling operations in hard lime where the tools got a good rebound, it required 50 to 60 amperes or from 30 to 35 horsepower. For drilling in shale where the bit muddied up, the ammeter showed about 60 to 70 amperes or about 35 to 41 horsepower. In pulling tools out and in bailing water, it usually required about 100 to 125

amperes or the equivalent of about 57 to 75 horsepower. As the motor was 75 horsepower and will stand a load of 100 per cent continuously, a 25 per cent overload for two hours, and a 100 per cent overload for two or three minutes, there was ample reserve power for any emergency that might occur.

"By changing the taps in the transformer banks the voltage was raised so that while drilling it would be about 440 volts. In that way the motor received the rated voltage during the operation, which was nearly continous.

"During the test, tachometer readings were taken while drilling in order to determine the 'kick' on the line when using a motor as compared with steam. Several tests were made on a neighboring steam well and on the motor well, but there was not enough difference to be noticed, so the 'kick' on the line may be taken as identical on the two outfits.

Difficult drilling encountered.—"A perusal of the daily report will show that this well had more to contentd with than the average well. There was much more bailing than usual, and this in turn caused considerable rig trouble. The bull wheel, band wheel and the sand reel had to be replaced. This, with other difficulties, caused many delays that otherwise would have been avoided.

"Water and caving increased the cost per foot drilled more than the average for electric drilling in California.

"The many advantages of electricity for drilling have been realized on this well from the start. The saving in cost includes the building of one house that will suffice for both drilling and pumping without a change. The initial cost of drilling motor and control is less than the cost of boiler and engine. The cost per day for drilling by electrical power is less than with steam. The water consumption is much less. There is also no fire risk and it is not necessary to move the motor away from the rig if gas is encountered. The depreciation of the electric equipment is very small, and repair parts are interchangeable. The motor used for drilling is supplied with screws at the bottom of the end shields, so that reasonable wear in the bearings may be taken up and thus the air gap may be kept balanced on all sides. With good oil in the bearings, it should not be necessary to do this more than once in eight months."

The cost of installation.—"The installation of the drilling motor was an experiment, and particular care was taken in making it so

that nothing, as far as we could see, would tend to make it a failure. The motor equipment consists of one 75 horsepower three-phase 60-cycle 440-volt Type M motor with base and pulley, mounted on a concrete block; 14 sets of grids, one primary and one secondary controller, and type K20 250-ampere circuit breaker, mounted on skids; one panel board, consisting of one 250-ampere 500-volt three-pole single-throw switch with cabinet; one 100-ampere Type D6 watt hour meter; one series transformer for a 250-ampere indicating meter which is mounted inside the rig in a convenient place so that the operator can at all times judge the load he is carrying on the motor. For 'safety first' we installed a small knife switch on the 'headache' post and connected it in series with the no voltage release so that in case of trouble or accident the operator could immediately shut off the power by opening it. For controlling the motor from the derrick, we installed two single-trees mounted on the 'headache' post with steel cable lines direct to both controllers.

"The cost of this entire installation was $2,955.99. After moving this outfit to Hess No. 16, we found that the salvage amounted to $2,188.96, making the total of the drilling installation amount to $768.03.

"This total cost of $768.03 includes the house, concrete forms and all labor. This cost can be spread over the installation of the pumping equipment, as the house and forms were of our standard design to fit both drilling and pumping equipments.

"At 8:30 o'clock in the morning of September 29 we shut down the well to remove the drilling equipment to Hess No. 16, and install the 30 horsepower 60-cycle 440-volt GE pumping motor on the Stokes well.

"The usual time required to put a well on the pump when it has been drilled by steam is four days, this being a very close estimate as it usually requires a few hours over the four days. The time used on Stokes No. 27 was exactly eight hours, or a saving of three days and 15 hours pumping. Since this well is estimated at 160 barrels production per day, this would give us a saving at $2.25 per barrel of $1305. If gas engine had been installed the loss in production would have been been at least double, or approximately $2,609.78."

Drillers' Opinion.—"Having worked on Stokes No. 27 from start to finish, my candid opinion is that electric power for drilling

is great. From a standpoint of economy and reliability, it has no equal. In spudding, drilling, bailing water, pulling tools or landing casing, the motor gave us not the slightest difficulty.

"The motor will bail faster and longer than any steam power I ever used. It takes a good 'toolie' to keep 120 pounds of steam on a boiler when bailing down a hole full of water after casing, or when carrying ten to fifteen bailers while drilling. With the motor it was easier to carry that quantity than to carry six to ten bailers with steam.

"Steam will start tools from the bottom of the hole faster than the motor, but when half out it will begin to lag, and any driller will tell you that many a time on a windy day, or with bad oil, they have had to wait for more steam before pulling to the top. With the motor, as the line increases the size of the coil on the shaft, the tools come out faster and faster and generally make it to the top quicker than steam.

"It was my pleasure to land the 10-inch casing at 1740 feet, 447 feet of which was extra heavy pipe. The string weighed approximately thirty-four tons. We had occasion to raise and lower casing in mudding off gas, and it was remarkable to note with what ease the motor handled the pipe. It was necessary to advance the control lever to only the fourth point, usually, in raising the entire string. In pulling casing, I could part any string in the hole in one minute, but it is so easy to control that it is not necessary to run up it on a loose line as with a steam engine. With a little judgment it is excellent for pulling casing."

Table Showing Comparative Saving

	Boiler and Engine	Motor	Loss	Saving
Initial cost	$1,862.00	$1,625.00		$ 237.00
Cost of installation (including belts, etc.)	432.50	*768.03	$335.53	
Estimated depreciation per well	290.00	32.50		257.50
Cost of water	480.00	60.00		420.00
Estimated cost of fuel oil at $36 per day	2,160.00			
Cost of electric power..........		574.93		

*The installation charge of the motor drilling equipment was high, due to the fact that the equipment was new and changes had to be made which involved labor charges that will not be necessary in future outfits. It also includes the cost of building the motor house.

Table Showing Comparative Saving.—Continued.

	Boiler and Engine	Motor	Loss	Saving
Saving in cost of power........				1,585.07
Saving in installing pumping motor in house on same foundation				186.16
Saving in oil production during change to pump				1,305.00
Totals			$335.53	$3,990.73
Net estimated saving of electric drilling over steam				$3,655.20

Deep Well Drilled in West Virginia by Hope Natural Gas Company.

Location.—On the Martha O. Goff farm of 620 acres in Simpson district, Harrison County, West Virginia, on the waters of the Owen Fork of Booth's Creek, four and a half miles northeast of the town of Bridgeport, on the main highway from Fairmont to Clarksburg, W. Va.

Elevation.—Location made for well March 3, 1916, at a point 1164 feet above sea level, and 200 feet below sea level of the Pittsburgh seam of coal.

Summary of drilling.—Drilling was commenced April 19, 1916, and on March 4, 1918, a depth of 7386 feet had been reached, thus exceeding by 37 feet the depth of well hitherto known as "the deepest well in the world," located at Csuchow, in Germany. Approximately 400 days have been spent in actual drilling, the remainder of the time the well has been shut down for repairs to rig, boilers, cables, etc., waiting for materials, minor fishing jobs, taking of temperatures, cleaning out cavings from the hole, etc. Fortunately, no serious fishing jobs have been encountered. The last known sand passed in the well was the Bayard sand, at depth of 2300 to 2310 feet.

Size of hole.—16 inches in diameter to depth of 217 feet; 13 inches in diameter from 217 feet to 1238 feet; 10 inches in diameter from 1238 feet to 2307 feet; 8 inches in diameter from 2307 feet to 7071 feet; 6 inches in diameter from 7071 feet to present depth.

Casing.—217 feet of 13-inch casing, set in slate; 1238 feet of 10-inch casing, set in Big Lime; 2307 feet of 8¼-inch casing, set in

Bayard sand; 1666 feet of 6-inch liner, set in well at 5405 feet to 7071 feet, to protect hole from caving.

Rig.—Standard (wood), 96 feet high with 22-foot base of extra heavy timbers. Bull wheel shaft 24 inches in diameter, with bull wheels 10 feet in diameter, triple tug, having 10-foot brake wheels, with 14-inch brake band on one side, 10-inch on other side; three sets of bull wheels have been used. Band wheel is 14 feet in diameter with 13 inch face, triple tug, carrying belt 18 inches wide, 150 feet in length. Sand reel has 6-inch steel shaft, with 16-inch friction and brake wheel, and weighs approximately 8,000 pounds, two of these sand reels have been used. Walking beam is probably the heaviest and largest piece of timber ever used for this purpose, with Pitman, connected to the walking beam, also of unusual size and weight. Crown pulley (top of rig) has 7-inch steel shaft, and weights 1,200 pounds. Four and one-half-inch standard rig irons were used to depth of 4500 feet, then replaced by special extra heavy rig irons (7½-inch) which have been used to present depth. Rig has been repaired from time to time. All work of erecting and repairing rig has been under the direction of George H. Stanfield, of Clarksburg, W. Va., superintendent of rig building for the Hope Natural Gas Company.

Boilers—

One 25- h. p. Acme, used from top of hole to 4,500 feet.

One 25-h. p. Brennen, coupled with the Acme at 4,500 feet, the two boilers then being used from 4,500 feet to 7,300 feet.

One 25-h. p. Acme, put on at 7,300 feet, the three boilers then being used from 7,300 feet to the present depth.

Engines—

One 12-12 Acme 25 h. p. used from top to 4,500 feet.

One 16x16 Oil Well Supply, 80 h. p., replaced the Acme at 4,500 feet and has been used from that depth to the present time.

Cables—

One second-hand Manila, 2¼x700 feet. drilled to 150 feet.

One second-hand Manila, 2¼x700 feet, drilled 150 feet to 615 feet.

One new Manila, 2¼x2,800 feet, drilled 665 feet to 2,290 feet.

One new wire, ⅞ in.x4,000 feet, drilled 1,070 feet.

One new tapered wire, ⅞x1x1⅛x1¼x10,000 feet, drilled 1,220 ft.

One new tapered wire, $\frac{7}{8}$x1x1$\frac{1}{8}$x1$\frac{1}{4}$x10,000 feet drilled 525 feet.

One new tapered wire, $\frac{7}{8}$x1x1$\frac{1}{8}$x7,350 feet drilled 790 feet.

One new wire, 1-in.x7,000 feet, drilled 32 feet, then used 48 days on cleaning out work.

One new wire tapered, $\frac{7}{8}$x1x1$\frac{1}{8}$x1$\frac{1}{4}$x10,000 feet, used one day, broke and was fished out of well.

One second-hand wire, 1-in.x5,000 feet, used one day.

One second-hand wire, 1-in.x7,000 feet, used one day.

Tools—

Drilled to 6,500 feet with string tools containing stem 34 feet in length, 5$\frac{1}{2}$-inches in diameter.

Drilled from 6,500 feet to 7,071 feet with string tools containing stem 40 feet in length, 4$\frac{1}{2}$-inch diameter.

Drilled from 7,071 feet to 7,386 feet with string tools containing stem 40 feet in length, 4$\frac{1}{2}$-inch diameter.

Summary of Record.—The log of the well might be summarized as follows, beginning at the base of the Pittsburg coal, 200 feet above the mouth of the boring:

			Thickness Feet	Total Feet
Pittsburgh coal, base of Monogahela Series, Conemaugh Series	600′	Penn.	1,150	1,150
Allegheny Series	290′			
Pottsville Series	260′			
Mauch Chunk	260′			
Mountain (Greenbriar) Limestone	65′	Miss.	590	1,740
"Big Injun," "Squaq" and Berea and Group	265′			
Catskill, containing Venaggo Oil Group, to base off "Bayard" Oil Sand	770′	Upper Devonian Shales	5,823	7,563
Chemung, Shales, containing "Elizabeth" Speechley, Bradford, Benson and Kane Oil Sand horizons	2,190′			
Portage Beds	1,207′			
Genesee Slate	288′			
Hamilton & Marcellus	1,368′			
Corniferous Limestone to present bottom			23	7,586

Temperatures

Depth		Mean Temperature	
Meters	Feet	Centigrade	Fahrenheit
30.5	100	13.11	55.6
61.0	200	13.51	56.3
91.4	300	14.15	57.5
121.9	400	14.97	58.8
152.4	500	15.67	60.2
182.9	600	16.42	61.6
213.4	700	16.92	62.5
243.8	800	17.49	63.5
274.3	900	18.07	64.5
304.8	1,000	18.51	65.3
335.3	1,100	18.76	65.8
365.8	1,200	18.62	65.5
396.2	1,300	19.18	66.5
426.7	1,400	19.57	67.2
457.2	1,500	19.87	67.8
487.7	1,600	20.01	68.0
518.2	1,700	19.89	67.8
548.6	1,800	21.53	70.8
579.1	1,900	23.13	73.6
609.6	2,000	23.84	74.9
640.1	2,100	24.52	76.1
670.6	2,200	25.19	77.3
701.0	2,300	25.72	78.3
731.5	2,400	26.58	79.8
762.0	2,500	27.2	81.0
914.4	3,000	30.9	87.6
1,066.8	3,500	34.3	93.8
1,219.2	4,000	37.8	100.0
1,371.6	4,500	41.8	107.2
1,524.0	5,000	45.7	114.2
1,676.4	5,500	50.2	122.3
1,828.8	6,000	55.6	132.1
1,981.2	6,500	61.8	143.2
2,133.6	7,000	67.3	153.2
2,209.8	7,250	69.8	157.7
2,228.1	7,310	70.2	158.3

Temperatures taken by C. E. Van Orstrand, Physical Geologist, United States Geological Survey, Washington, D. C.

Improved Methods of Deep Drilling in the Coalinga Oil Field, California[1]

In this territory the formations drilled through are chiefly sands and shales; they will not "stand up" in an open drilling hole; the casing has to be carried close to the bit, and it is always difficult to keep the casing free for any considerable distance.

Ability to carry casing of comparatively large diameter without conductor pipes for distances of 2,000 or 3,000 feet or over is desirable in such territory chiefly for two reasons. It makes it possible to enter the oil sand with a pipe of ample diameter; it eliminates one or more expensive strings of casing which act only as conductors for the water string, and furthermore, in territory where waters are encountered which corrode steel rapidly, it makes possible the construction of a rust- and alkali-resisting water string.

It is always desirable to shut off top waters, which may lie within 100 feet or less of the oil sand, with 10-inch pipe. Where the depth is so great that a practical weight of 10-inch pipe will not withstand the probable collapsing pressure, 8¼-inch at least is desirable.

About the limit of rotary drilling to date in California seems to be the setting of the 10-inch string at 3,200 feet, although the rapid advance in rotary work during the past years seems to indicate that this depth may soon be increased.

The problem is to reach a depth of 4,000 feet or more with a string of pipe not less than 8¼-inch in diameter for shutting off top water, and to reach it with this string free and movable and using in the upper part of the hole the minimum of conductor casings.

In the Coalinga field some very promising results have recently been obtained by a method, or combination of methods, effected by William Keck. In one well a 15½-inch string was set at 2,300 feet, and a 12½-inch string through this at 3,003 feet, these being the only strings used in the well to that depth and both being landed when they were entirely free. In another well a 15½-inch string was set at 2,100 feet and through this a 10-inch string at 3,300 feet, in this case also the strings were perfectly free when landed and were stopped only because it was not desired to carry them deeper. Other wells have shown similar results.

[1] M. E. Lombardi in Trans. A. I. M. E., February, 1915.

It will be noted that the 15½-inch strings were free with over 2,000 feet of "friction" on them, and this in a territory that will not "stand up" with ordinary drilling more than 40 or 50 feet ahead of the pipe.

The drilling detail used on these wells is briefly as follows: A large clearance for the pipe is obtained; the standard circulator system is used; the pipe is kept moving while drilling is in pro-

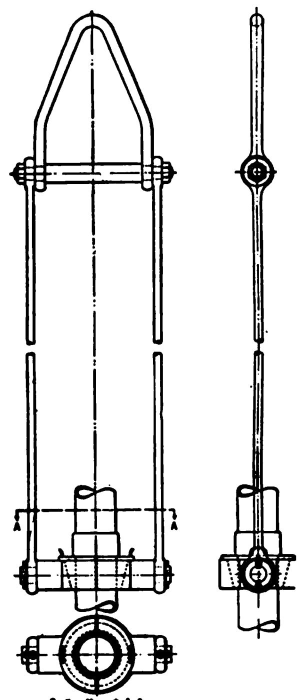


Fig. 31—Swinging Spider

gress; each collar is "set up" twice before it goes below the bottom of the derrick cellar.

The large clearance is obtained by the use of a shoe of extra

large diameter, from 1¼ to 1¾-inches larger than the collars on the pipe. Underreaming is resorted to frequently and the hole is repeatedly underreamed until the pipe is entirely free in passing a "shell" or hard streak. Spudding the pipe is avoided. When a conductor pipe is landed the desirable extra clearance for the next string may be obtained by skipping one size of pipe, as for instance carrying a 10-inch string through a 15½-inch, thus eliminating the 12½-inch size. This is necessary with the present sizes of pipe available, but a different design, which will be mentioned later, would save considerable expense in this matter.

This extra clearance is necessary in using the circulator system to allow free passage for the "returns." It obviates the danger of sand lodging between the strings of pipe and freezing the working string.

The Circulating System.—The well-known standard circulator system is used. Mud- (clay) laden fluid is forced down through the pipe under pressure by the pumps (ordinary rotary slush pumps) and returned on the outside of the pipe, carrying the drillings with it. This fluid is run through a flume and into a pit, as in rotary work, and its consistency is regulated as with the rotary.

This mud-laden fluid presumably plasters up the walls of the hole, prevents sand and mud from running in and prevents caving. It is essential that circulation be interrupted as little as possible. Intermittent circulation seems to be worse than useless.

The pipe is kept moving while drilling is in progress, i. e., without pulling out the tools—by means of a so-called swinging spider. The pipe is suspended by an ordinary spider provided with lugs to which are attached steel reins (sometimes chains or wire lines) which extend to a clevis above the walking beam, the beam operating between the reins. The clevis is attached to the casing block. The reins are about 40 feet in length so that the pipe may be lowered to the bottom of a 30-foot cellar. The cellar is made deep enough so that the stationary spider at the bottom is more than the length of one joint of pipe below the derrick floor. It follows that when a joint of pipe is added to the string the back-up tongs may be put on the second collar, which has been previously set up and which is now near the cellar bottom. The same result is obtained without back-up tongs, the pipe being held by the lower spider.

Thus every joint is set up twice—once when it is put on, and a second time after it has been subjected to the pull of the pipe below it and the vibration of drilling. This insures a tight joint.

It is by a combination of the above details and careful attention to them that success in carrying pipe has been obtained.

Other advantages are obtained, one might say, as by-products of this method. The pipe is always free and the circulation perfect for cementing, the mud being easily washed out ahead of clean water. There is almost total elimination of bailing out drillings, with its consequent loss of time. A lifting pressure may be put against the closed top of the casing, thus relieving to some degree the strain on the casing line. For instance, a 12½-inch casing has an area of about 121 square inches; a pumping pressure of 200

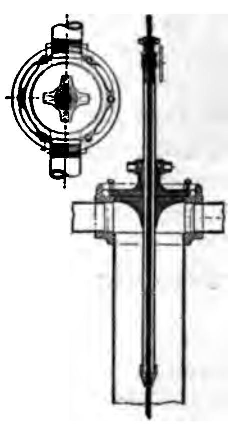


Fig. 32—Circulating Head and Oil Saver

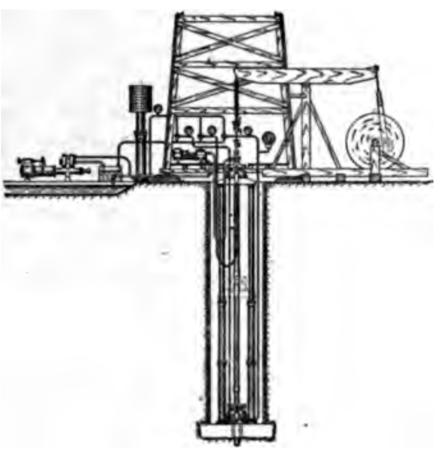


Fig. 33—Hydraulic Elevator for moving casing used in connection with circulator system

pounds per inch against this means 24,200 pounds taken off the effective weight of the casing. Naturally the pressure runs up if the pipe becomes loggy and that is when it is most needed.

The mud-laden fluid as usually used has a specific gravity of about 1.40; therefore, its pressure in holding back artesian water, running sand, etc., is 1.4 times as much as clear water. It is a well-known fact that this mud-laden fluid tends to kill gas (see Technical Paper No. 66, U. S. Bureau of Mines, Mud-laden Fluid Applied to Well Drilling), although it is the writer's opinion that the

capillary action of water in sand has as much to do with holding gas pressure back as anything.

It has been suggested that in territory where upper waters corrode iron and steel very fast, a 10-inch water string practically immune to this corrosion may be obtained as follows:

Carry a 12½-inch string within a few feet of the point where water is to be shut off. This string may be as light and cheap as it is practical to carry, since the burden of sustaining the collapsing pressure of the water does not fall on it. Then land a 10-inch water string inside of this 12½-inch string at the proper point below it, and pump in enough cement to fill the space between the two strings.

This is mentioned simply as one of the advantages which may accrue from a drilling method by which a large-diameter string of pipe can be carried to depth with reasonable certainty.

Now as to the interesting item of cost. The bulk of the extra cost incurred is in movable tools and machinery, only the depreciation and upkeep on which are chargeable to the well drilled. Extra cost incidental to the drilling itself, other than above, consists in construction of the deep cellar, the installation of one extra boiler, the mud pumps and the extra fuel and water used, and one extra man. The swinging spider, pumps, boiler, etc., are, of course, moved and used for successive wells.

An idea of the extra cost items may be gained from the following:

Extra depth of cellar, drain and circulator rigging		$ 450.00
Setting of extra boiler and circulator pump		250.00
Mud flume, pits, etc.		100.00
Total fixed costs per well		$ 800.00
Extra labor in drilling, per day	$ 7.00	
Extra fuel, 7 bbls. of oil per day at 35c	2.45	
Extra water, packing, etc., per day	4.00	
	$13.45	
Total extra cost per day for 122 days		1,640.00
Depreciation at 18 per cent on $2,320, being value of outfit removed		136.00
Total extra cost		$2,576.90

In a typical well with the system under discussion 3,336 feet of 10-inch pipe was set in 122 days.

This is the value of only about 1,465 feet of 12½-inch 45-lb. casing f. o. b. the field. No 12½-inch casing was used, so at least this amount was saved.

Better average time is made with this method, so that at the most it is not more costly than the usual cable tool drilling. As pointed out, its chief value lies in the fact that large-diameter pipe can be carried to depth with far more certainty.

It is impossible to leave this subject without a few suggestions for the future; in other words, indulging in a mental construction of an ideal drilling outfit, built along lines following the above described method.

A greater clearance between consecutive size strings of casing is essential. In order to shut off water with a certain size string, the conductor used, be it long or short, should have an inside diameter at least 1¾-inches greater than the outside diameter of the collars on the water string. Since the water string will have to stand great collapsing pressure and must therefore have very thick walls, a clearance should be provided in it so that the oil string may be worked without difficulty.

If it is desired to use an 8¼-inch oil string, it follows that the water string should be at least 10⅛-inch inside diameter, which would be obtained in a casing of 10⅝-inch nominal diameter weighing from 55 to 60 pounds per foot. This would call for a 14-inch conductor.

Requirements for the ideal casing are:

Sufficient thickness of walls to withstand water pressure; joints that will hold on a maximum pull; threads that will stand being set up several times; reduction of weight near the top of the string.

To meet these requirements the casing will have to be heavy on the bottom and light on top, but the top part will have to stand the greatest pull. Obviously an upset-end casing, upset on the outside, would be the thing for the top part of the string. Furthermore, with these upsets and with the thickness of the wall necessary on the bottom of the string, eight threads per inch could safely be used in the joints. It is well known that eight threads will stand more unscrewing and screwing up, more driving and, in general, more "grief" than the customary 10 threads.

Collars may be built correspondingly heavy since excess clear-

ance is obtained anyhow. In explanation of the desirability of using eight threads I would say that in carrying a string of casing a long distance there are generally accidents, such as pinching a shoe, etc., which necessitate pulling and putting back the casing before it is finally landed.

The swinging spider, although efficient, is clumsy. In moving casing with it in the ordinary way, the entire strain (sometimes 80 tons or more of casing, plus friction of the mud between the casing and the walls of the hole, must be moved) is transmitted to the crown block on top of the derrick. To obviate this and carry the greatest strains on solid foundation, a hydraulic elevator operating in the cellar might be used. Such an elevator with a lift of 22 feet has been devised, but never used to my knowledge. (See Fig. 33.) By its use casing could be kept moving all the time, and all hard pulls taken off the crown block. Of course, the ordinary elevators and calf wheel would still have to be used, for putting in and pulling strings of pipe, but the heavy work could be carried by the hydraulic elevator in the cellar, and the cost of constant repairs to the derrick considerably lightened. Pulling in of derricks, with consequent delays, frozen pipe, and danger to life, now far too frequent, would be almost entirely done away with. With the above suggested improvements, it seems reasonable to expect that an 8¼, 10, or 10⅝-inch water string, with only a few hundred feet of conductor, could be carried in the territory under discussion to 4,000 feet or more.

Fishing Tools—Cable Tool Wells

The kinds of fishing tools for cable tool drilled wells are of necessity very numerous owing to the varied nature of troubles that can arise in the drilling of a well by this system. Some of the more common are shown herewith together with a short description of each.

Rope spears.—As shown in Fig. 33a there are various kinds of rope spears. They are used for recovering drilling and bailing lines from the well. The particular form to be used depends on the condition of the lost line in the hole.

Latch jacks or boot jacks.—These are shown in Fig. 33b. They are used to catch the bail of a lost sand pump or bailer and to take

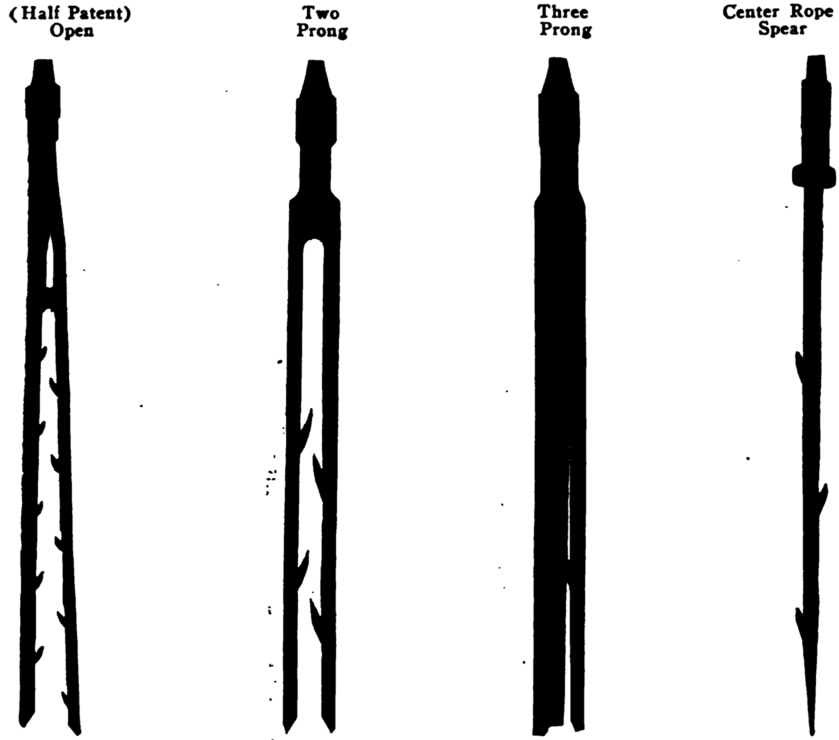


Fig. 33—Types of Rope Spears

hold of the lower half of jaw under the head when the upper half is broken off.

Slip sockets.—This is the tool commonly used to recover a string of lost tools or a lost bit, stem, or jar. They will take hold of any tool when the pin has been broken off. (See Fig. 33c.) For running in a hole of larger size than the socket, barrels are furnished which can be bolted to the bottom of the socket. In fishing for a bit or tool which is leaning over in the side of the hole it is good practice to lag a timber on one side of the socket so as to throw it on the side of the hole.

Combination socket.—As shown in Fig. 33d, this tool contains slips for catching either a pin or barrel of rope socket. This tool is used quite extensively when conditions are right.

Side Opening **With Bowl** **Bowls for Sockets**

Fig. 33-d—Combination Sockets

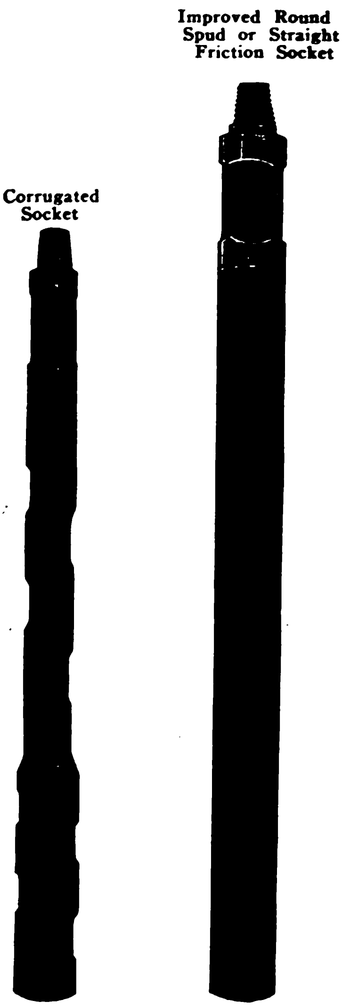
Rasps.—These are used for filing or rasping off the side of the collar of a tool which has been drilled on. By dressing the collar down in this manner they are able to get a slip socket, horn socket or other tool to go over the lost tool and take hold. (See Fig. 39g.)

Hollow reamer.—This tool, shown in Fig. 33n, is used to remove cuttings and cavings from around the top of a lost tool in order to provide sufficient room for the fishing tool to take hold. They are also used in cleaning out down to the lost tools.

Whip stock.—This tool is set in the hole on top of a lost string of tools when it is desired to drill by. The whip stock causes the tools used in drilling past to glance off into the side of the hole.

Whip stock grab.—(Shown in Fig. 33-j) This tool is used in recovering the whip stock from the hole.

Bell sockets or mandrel sockets.—As shown in Figs 33-l. This tool is used to take hold of casing that has been lost in the hole or a bailer body from which the bail has been removed. Only one or two joints of casing can be removed at a time with this tool.



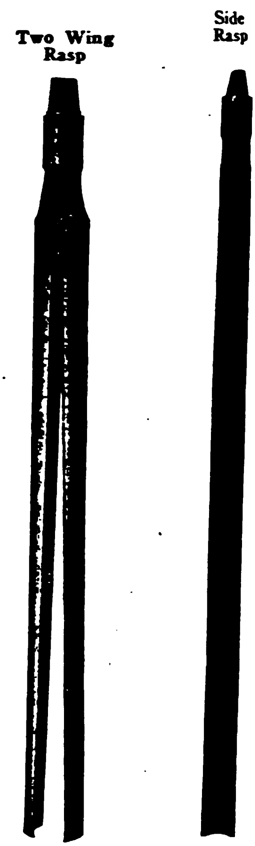


Fig. 33-e—Horn and Friction Sockets Fig. 33-f—Spud Fig. 33-g—Rasps

Collar sockets.—These are used to take hold of collar of a tool lost in the hole. (See Fig. 33m.)

Rope socket tongue sockets.—Used for taking out lost rope sockets. The tongue goes on the inside of the rope while the body of the tool goes around the socket. The two slips catch and hold the socket fast. See Fig. 33-n.

Drive down socket.—This tool is shown in Fig. 33-o. It is used

to cut a "head" off of a rope socket or to reduce the size of the barrel of a rope socket. This tool can also be used to cut a short piece of cable from the rope socket.

Jar knocker.—This tool is run on the sand line and is used to knock the jars loose when they become locked, thereby permitting tools to be loosened. (See Fig. 33p.)

Bulldog pin socket. — Is used to take hold of pin on lost tool. It has no springs. (See Fig. 33-q.)

Tools used in fishing for lost jars.—In Fig. 33-r are shown various sockets used in fishing for lost jars, or for broken jar reins. The particular style used depends on the condition of the part of the jars which is to be encountered in the hole. To catch one jar rein the jar tongue socket or center jar socket is used. To catch both jar reins the jar socket is used. To catch the jar tongue the slide jar socket is used.

Fig. 33-h—
Hollow Reamer

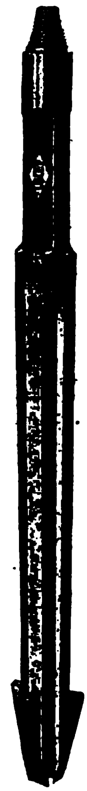


Fig. 33-j—
Whip Stock Grab

Wall hooks.—These are made in various lengths and are used to straighten a bit in the hole. (See Figs. 33-s.)

Wire rope knives.—At all times when the string of drilling or fishing tools become stuck so that it is impossible to pull them by jarring or otherwise necessary to run a rope knife into the hole on the cable and cut the cable as close to the rope socket as possible. Rope knives are of various kinds, one of which is shown in Fig. 33-t. They are run on the bailing line. As soon as the line has been cut and the cable and knife removed from the hole a string of fishing tools with long stroke jars and the proper socket is run into the hole.

Fig. 33-l—Mandrel Sockets

Fig. 33-m—
Collar Socket

Fig. 33-o—
Drive Down Socket

COMMON CABLE TOOL FISHING JOBS[1]

Fishing with die coupling.—Steel die nipples and die collars (Fig. 34a) are used to recut threads on a lost string of pipe and to act as a coupling after the screwing on has been completed. They are made so that they may be inserted in a collar or over the thread of a joint of pipe, and, when necessary, may even be used where the thread of the joint has been broken off and the top of the pipe is left intact.

A die coupling, either steel nipple or collar, can be used successfully at any reasonable depth. The die is a case-hardened tool

[1]By Thos. Curtin. U. S. Bureau of Mines. Bulletin No. 182.

and can not be driven without danger of breaking, although it may be pulled upon with safety when properly screwed on. Such tools can not be used successfully on a "water string," as they are not water-tight. A die coupling should be selected that will not hinder the passage of tools; if not carefully selected, it may be discovered after the parted pipe is coupled together by means of the die nipple or collar that various drilling tools which are "flush" with the hole will not pass through the die coupling. This often happens with die nipples and collars used in the Mid-Continent field, and is a matter of serious concern if the pipe thus coupled is frozen or in such condition that pulling it out is not feasible. It is then necessary to turn all tools, such as underreamers, swages, etc., down to a size that will permit their free passage through the die coupling, because the unscrewing of such a coupling at any great depth, without unscrewing collars above the coupling, is almost impossible.

Fig. 33-p Jar Knockers

Method of screwing on.—The die coupling is placed upon the bottom of a string of pipe of the same size as the pipe lost in the hole. This "fishing string" is then run into the hole until the tool rests lightly upon the upper joint of the lost string. The fishing string is then turned slightly until a "drop" is felt at the surface. This "drop" is evidence that the tool has dropped into place and is resting properly upon the lost string, ready for screwing. No drop will be felt if, perchance, the tool landed in perfect order for screwing when first set upon the lost string. Pipe tongs are now put to work turning the pipe at the surface with engine power, the weight of the upper pipe being permitted to rest upon the lost pipe.

For some sizes of pipe ball-bearing races have been provided, which sit beneath a collar and on elevators and are adjusted to support the unnecessary weight of the fishing string. These races, however, are seldom obtainable, so it is here assumed that they are not in use.

As the pipe is screwed on with the engine and the die coupling begins to cut threads, little satisfactory progress will be made un-

Fig. 33-q—Pin Socket

With Band

Fig. 33-r—Jar Tongue Sockets

less a second pair of tongs is used to hold the back spring—caused by the tortion obtained on the pipe—before the die coupling at the bottom turns and cuts.

A mark should be kept upon the fishing string. As the die coupling screws on when cutting its way, the fishing string will settle the same distance if no couplings in the fishing string also screw up. However the couplings are almost certain to take up, but as their action can be readily felt, the amount of this "taking up" should also be judged. As the die coupling makes headway a continuous increase of power will be required to turn it. The point at which to stop screwing is determined by the surface indications resulting when engine power is applied, such as the strain on the tongs, the amount the pipe has settled, etc. The two strings of pipe should now be fastened firmly together and in condition to be pulled when desired.

Use of casing bowl.—P. D. Tanguey, a master mechanic employed by the Shell Company, of Coalinga, Calif., manufacturers for the use of that company a casing bowl, shown in Fig. 34b. The drilling foreman of this company uses this tool almost to the exclusion of die collars in work that ordinarily calls for a die collar.

Fig. 33-r—Various types of Jar Sockets

The slips of this tool being very thin, permit a hold to be taken upon the outside of the lost string of pipe.

Like the die coupling, a casing bowl can not be driven upon and will not exclude water. It will, however, permit a free passage to all tools and is capable of withstanding very hard pulling, but is only serviceable when there is no coupling on the top joint.

W. A. Snyder, also of the Shell Company, who had occasion to use this tool on numerous occasions, regards it as more adaptable to the same class of work than the die coupling, as the time and labor incident to screwing on with the die coupling is unnecessary with the casing bowl.

The casing bowl is run into the hole in a manner identical to that described for the die coupling, but once the bowl has slipped over the lost string of casing its action is instantaneous, as it takes hold of the lost string when pulled up, and the pipe is thus connected.

"Bad pipe."—Frequently pipe remaining in a hole for some time will "go bad." This expression refers to pipe that has become dented from a "stone bruise," is in a state of partial collapse from outside wall pressure or gas pockets, or perhaps in split and partly flattened. The pulling of such pipe for the purpose of replacing the damaged joints is often inadvisable because of the danger of parting the pipe at the "bad place," leaving the lower part of the string in the hole. Such pipe is often "frozen" and attempts to free it would cause the weakened joints to part.

Bad pipe is usually first detected by the bailer hesitating in its drop as it is let down the hole. This hesitation recurring continu-

ously in the same place leads the driller to suspect that the pipe is giving way at that place. As any slight dent in the casing is bound, from time to time to meet the full shock of all tools being run in the hole, it is usually only a matter of time until such a place in the casing becomes so impaired as to cause the bailer to "stop up." Before the pipe has become too badly damaged the bailer can be worked past the obstruction and at times will entirely miss it, gliding past with scarcely a halt. The obstruction is next noticed with the drilling tools and eventually becomes so "bad" as to cause the tools to "stop up." The bailer will seldom pass through pipe sufficiently "bad" to obstruct drilling tools in their passage,

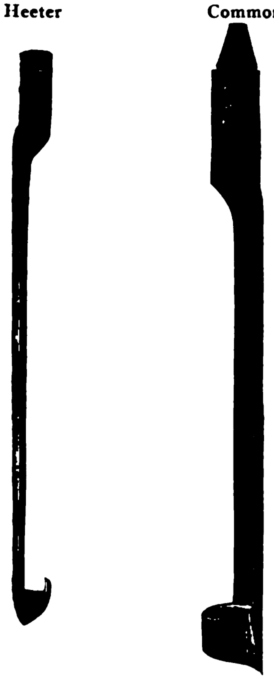


Fig. 33-s—Wall Hooks

Fig. 33-t—Spang Wire Line Knife for cutting cable, 1-inch diameter or smaller.

Knife will cut a 1-inch or smaller drilling cable or sand line in 4⅝ or larger casing. Notice the plunger drive direct against the cutter knife. The cutting can be done by using rods, pipe or sand line.

This knife can be put on the cable to be cut in one minute and will not cut the cable until it strikes the top of the rope socket, bailer or pump.

This outfit consist of 1 knife, 1 extra blade, 1 set 4-foot jars, 3--1¼x10 feet sinkers, 1 ball bearing swivel.

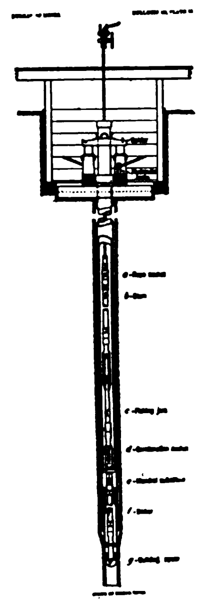


Fig. 34.—String of Fishing Tools.

although this condition may be overcome for a time by replacing a full-size bailer with one of smaller diameter.

Swaging.—One of the remedies for "bad pipe" is swaging. The swage is a heavy piece of steel, oval in shape, with a small groove cut into the steel as a watercourse. At its greatest diameter the swage is but a fraction of an inch smaller than the diameter of the casing through which it must pass. Thus, casing with a 10-inch inside diameter should permit the entrance of a swage 9⅞ inches in diameter. As the ultimate desire is to "run" a swage of the greatest diameter that the size of the casing will permit, a variance of even one-sixteenth of an inch is a matter of importance.

The swage is run below the stem, with long-stroke fishing jars immediately above the swage. The tools are run into the hole until the swage stops upon the "bad place" in the pipe. The "hitch is taken for "driving" or "jarring down" as described on page 11. As the swage drives ahead from the impact of the stem and jars, the screw should be let out enough to keep the jars continually hitting down. When the swage has been driven through the "bad place" and has entered the "good" pipe below, the tools will swing free. When this occurs, the weight of the heavy swage being now added to that of the extended jars causes an unmistakable change in "motion" and cable tension. An attempt should now be made to pull the swage back up through the "bad place" in the casing. In all probability

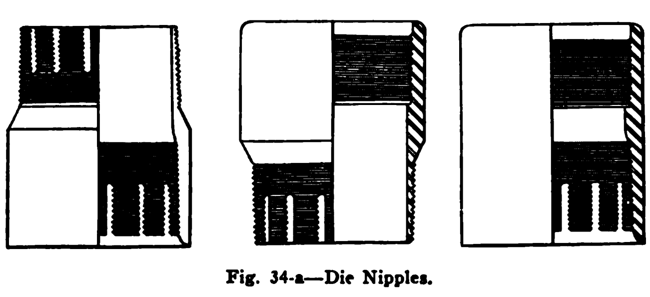


Fig. 34-a—Die Nipples.

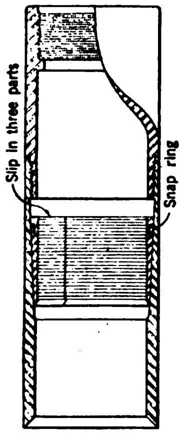


Fig. 34-b—Casing bowl; may be used in place of a die collar; permits passage of tools.

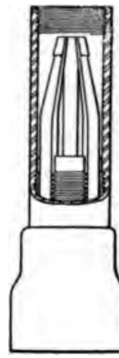


Fig. 34-c—Overshot. The springs pass down over pipe and couplings, but catch under a coupling when pulled up.

the swage will have to be "jarred" back through this place. The operation of driving the swage down through the "bad pipe" and jarring it back through the same place should be repeated until the swage will pull freely through the impaired pipe. It can now be safely assumed that the pipe has been extended to its normal size.

Remarks concerning swaging.—When a difficult swaging job is expected, the common method of procedure is to drive a swage of small diameter through the "bad place" first. This swage is then withdrawn and a swage of greater diameter is used. This procedure is repeated until a swage of maximum diameter is driven through the impaired pipe.

If a swage has been driven through a split joint of casing and cavings are falling into the hole through the split, great care should be taken to prevent the cavings from wedging the swage in the hole—the tool being so nearly "flush" with the hole that any hard obstacle may cause it to wedge. Pulling the swage above the split pipe from time to time will act as a preventive against wedging, and in case the swage does not pull freely it should be pulled out and cleaned. A swage wedged in casing is a difficult tool to remove, as it is not unusual to jar a pin off in attempting to jar the swage past cavings or broken pieces of pipe that may accumulate above it, unless care is taken. It is always possible to jar a swage up through pipe through which it has been driven if no debris has accumulated upon the top of the swage.

Pipe has seldom, if ever, been severely injured by a swage, but should not be swaged if avoidable, unless sitting on a shoulder or bottom. Pipe, if hanging in the hole, may easily be parted with a swage.

Swaged pipe frequently goes bad a second time, necessitating a repetition of swaging. It may be considered that the pipe is weak-

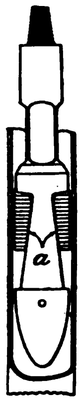


Fig. 34-d — Bull-dog casing spear. Once the tool takes hold it can not be withdrawn because upward movement will cause the slips a to slip down the inclined plane and lodge against the pipe.

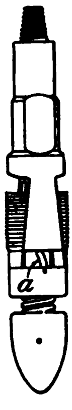


Fig. 34-e—Trip casing spear. When the spear is driven upon with tools, the small trigger a snaps into place, as shown, permitting the spear to trip and be withdrawn.

ened with each swaging. Where possible an inside string of pipe should be inserted with a tapered guide of wood or cast iron upon the bottom of the shoe to guide the shoe through the swaged pipe. This pipe will ordinarily keep the hole in better condition.

Tools with swage attached should never be raised above a "bad place" in the casing and allowed to descend swiftly. When this is done, if the swage stops in the "bad place" in the casing and is then knocked through with one blow by the descending stem and jars, the swage being heavy may fall so forcibly as to "jump" a pin when the jars receive the weight of the swage. This practice is especially dangerous where two sets of jars are used.

Collapsed casing.—Pipe in a hole usually goes "bad" gradually, and may sometimes collapse gradually, but as a rule collapsing takes place instantaneously and often above tools in operation, causing them to be shut in below the collapsed pipe.

A typical example of collapsing casing occurred in a wildcat well in Colombia, South America. The hole was 2,210 feet deep. Ten-inch pipe of a standard make weighing 40 pounds to the foot was being used. The pipe was in good condition, but because of circumstances unnecessary to explain, it was decided to land the pipe and bail the hole.

The pipe was landed and bailing of the hole was commenced. The water was lowered to a depth of 1,150 feet. At this stage of the work the pipe collapsed at 1,600 feet. There was a sharp report resembling the explosion of a charge of dynamite in the hole, and a rush of air which blew the hats off the men who were standing near the hole. This was followed immediately by a column of water that gushed to a height of about 50 feet. The water was

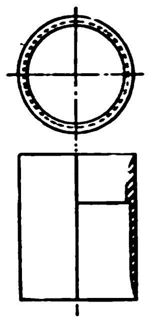


Fig. 34-f—Casing adapter, for adapting one size of casing to another, and permitting tools to be lowered into the well.

followed by gas, making it necessary to extinguish the fires under the boilers.

After collapsing, pipe will often be completely sheared off, and the damaged pipe pulled out will be flattened and split. The presumption is that the top of the pipe left in the hole is in the same condition. However, more often the pipe, although badly flattened and split, will cling together, which necessitates driving at the top with tools and drive-clamps before the shattered pipe will break.

Drilling past or sidetracking casing.—Drilling past pipe is a comparatively easy matter in caving territory, but a very difficult undertaking where the formation is hard and "stands up" The necessity for drilling past pipe in hard territory, however, is far less frequent than in caving territory. The conditions liable to collapse are more frequently found where the formation caves, and in such a formation the remedy is the more easily applied.

Time consumed in drilling past.—When confronted with a job that necessitates "drilling past," the operator, unacquainted with the process, believes that the time and risk involved may make moving the rig and starting a new hole more practical and is doubtful as to which is the better method of procedure.

When the territory is suited to "drilling past," the redrilling often proceeds, after a successful initial start, far more rapidly than did the original drilling of the same formation. The greater facility of redrilling is accounted for by the formations having been somewhat broken by the original drilling and by the cuttings from the tools finding an inlet to the old hole. The elimination of the cuttings in this way keeps the

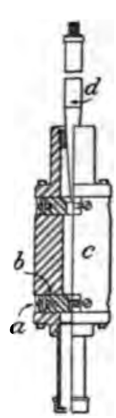


Fig. 34-g—Casing cutter. a, knives; b, steel blocks; c, steel frame; d, mandrel.

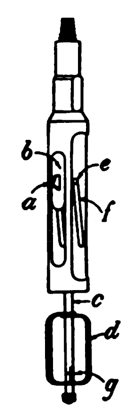


Fig. 34-h—Casing splitter; a, knife; b, sliding block; c, mandrel; d, spring; e, steel pin; f, inclined slot; g, trigger.

hole much cleaner with less bailing than in the original drilling.

It will also be found that the underreamer is used less than in the first drilling. The formation seems to break to a greater width from the impact of the bit alone, and hard strata that occasioned the use of the underreamer when the hole was first drilled, are often undetected in the second drilling.

Ultimate condition of hole.—It can not be maintained that drilling past a string of casing, and carrying a second string of pipe to the intended depth past the old casing, leaves a hole in as perfect condition as it would in the event that sidetracking had not been necessary, but the general results of such work are highly encouraging. There is little more reason to expect trouble from a string of casing landed successfully by drilling past an old string than there would be if the conditions were otherwise, although the new string may suffer from the causes that occasioned the original casing to fail.

"Sidetracking" a common practice.—Sidetracking casing is such a common, in fact, daily occurrence in many localities that citations from the hundreds of examples where such work has been successfully performed is unnecessary. One of the many instances of such work will be enough—that performed on well No. 4 of the American Petroleum Company, section 30, Coalinga, Calif. This well—an old producer at the time of the writer's knowledge of it—had 10-inch pipe broken off within, and successfully sidetracked on four different occasions. On the last occasion the 10-inch pipe was pulled, but more than 250 feet of the string was left in the hole. The bottom joint of the pipe pulled out was replaced with a new joint, a 10-inch shoe being used. The lost pipe was sidetracked, the new string landed, and the well put to tpumping within two weeks.

In the example cited on page 117, where the pipe collapsed at 1,600 feet, the original depth of the hole was 2,210 feet. The 610 feet of hole, thus lost by the collapsing of the pipe, was redrilled in less than one-third of the time consumed in drilling the original hole.

Tools used in sidetracking casing.—Tools used in sidetracking casing are many and varied when the work does not proceed with the ease anticipated. They are largely a matter of individual choice and construction, however, and usually are dispensed with

in favor of the ordinary drilling tools. Bits are sometimes drawn far out to one side until they are bootlike in appearance, upon the theory that the extended point will reach a troublesome sliver of the old pipe that may be obstructing the passage of the new pipe. Reamer bits, flat on the surface and rounded to the "full" of the hole, are also used, but although the reamer bit is recommended, unless the job is of an unusual kind, the ordinary drilling tools suffice for all purposes.

Importance of clean start.—In drilling past is has been proved that if the work be not unduly hurried in the beginning, and the pipe receives a clean start past the top of the old pipe, the work will progress more favorably than if this start is forced.

A bit is put to work, as in ordinary drilling, upon the top of the old pipe. After enough progress has been made for the insertion of a joint of casing, the pipe should be "tried." If the slivered casing obstructs the passage of the pipe, the hole should be underreamed until the barrier is forced into the wall or broken off. When this happens the first joint of pipe will start past the old pipe. From now on ordinary drilling problems only are met, with the exception of an occasional troublesome sliver of the old pipe interfering enough to cause momentary delay.

Odd features of sidetracking pipe.—The new casing should be raised only when unavoidable, as the old pipe often falls back into the hole if the casing is raised, thus necessitating a repetition of the work.

Turning the casing will often cause it to pass a sliver obstructing at an unexpected moment. On the other hand, an unfortunate turn of the casing will sometimes cause it to encounter an obstruction at a place in the hole through which it had previously passed freely. This action of the casing is referred to merely to illustrate the peculiar behavior of casing at times and not because it is of great importance.

After the initial start, the old pipe may not again be encountered. In most cases, however, when freedom from contact with the old pipe is maintained throughout the greater part of the redrilling, the bottom joint of the old string will be encountered and some trouble will be met in passing.

The balance of opinion as regards the choice of shoe to be used for this operation favors a plain shoe. It is contended that the

occasional advantage obtained by a tooth shoe in eliminating a sliver is more than offset by the tendency of such a shoe to create slivers and catch others that a plain shoe would pass.

Fishing With Overshot.—Of the innumerable tools for pipe fishing, the writer has chosen the overshot (Fig. 34-c) as being sufficiently important for detailed description.

Overshots have three flat springs about 16 inches long, 1¼ inches wide, and ¼ inch thick, but varying in size to correspond to the size of the overshot. The springs are held erect within a steel bowl. When the overshot comes in contact with the top of the lost pipe, it slips over that pipe, and travels down over the collars. If unhindered by cavings or other obstacles, the overshot can be run to the bottom of the hole. The well then has one string of pipe within another. When the overshot is raised the upright springs catch under a collar of the lost or inner pipe and this pipe, if free, can then be pulled; however, should it not be free, and the outside string be known to be the stronger, the inner pipe may be pulled apart. The overshot, although a delicate appearing tool, is capable of withstanding considerable strain. This tool is an excellent one for catching tubing or casing that has been dropped and is broken and crooked, provided it is reasonably certain that the casing or tubing has not become fast in the hole so that excessive strains will be required to pull it.

Fishing with casing spears.—There are many types of casing spears manufactured for fishing out casing. However, they may be classified under two heads—bulldog and trip spears.

Every care should be taken to avoid running a spear below a breach in the pipe that will permit debris or broken pieces of casing to fall upon the spear. Under such adverse circumstances the best trip spears are likely to "bulldog" in the pipe and they are a very stubborn tool to remove when once "fouled."

Regardless of selling advertisements to the contrary, spears of whatever make will damage pipe, at the point of contact of slips and pipe, if heavy jarring is continued too long in one place without changing the "hold." When the hold should be changed is a matter depending entirely upon the judgment of the driller and the weight and condition of the pipe for which he is fishing.

Bulldog spears.—Bulldog spears are so constructed that once the spear is run into the pipe being fished for, it can not again be

raised without taking all or part of the pipe with it. In other words, the hold may be broken and a lower hold taken, but the spear can not be pulled up without gripping the pipe. Before running this tool, if a stubborn jarring job is anticipated due care should be taken that all equipment is in good condition, because "something has to come." The pipe must either be freed in toto or jarred apart and an upper part removed.

Trip spears.—Trip spears (Fig. 34-e) are so constructed that the hold may be broken and the spear withdrawn at the will of the driller. Trip spears are made with two and four slips. The 4-slip spear is intended to be less injurious to the pipe than the 2-slip spear. The spear that is less liable to damage pipe permits the longest "jarring" in one spot without changing "holds."

For stubborn jobs, whenever obtainable, trip spears should be used in preference to bulldog spears. Should any accident occur and be detected, such as the slow unstranding of a wire cable due to a broken strand, or should the job prove stubborn enough to require a change of method, or should any one of innumerable reasons demand that the hold be broken and the tool pulled out, the use of the trip spear would permit this being done.

Jarring up with spear.—Assume a hole to be 2300 feet deep and the pipe frozen. Light driving at the surface with clamps and drivehead would probably be the first step after precaution was taken to keep the pipe from dropping. This failing, the jar-down spear would be used. Should the jar-down spear also fail, the "friction" would be ascertained by obtaining vibration before withdrawing the spear. A trip drive-up spear would now be placed upon the fishing jars left on the bottom of the stem when the jar-down spear was removed. Assume that the "friction" has been found to be behind the last 200 feet of pipe or between depths of 2100 and 2300 feet. The "stretch" of the casing would first be taken and held; a hold would then be taken in the pipe with the spear at 2270 feet or about midway in the second joint from the bottom, or midway in the shoe joint, if preferred.

Jarring up would now be started. The hold would be changed, from time to time, according to the possibility of its injuring the pipe. Signs of vibration in the pipe would be watched. The spear having hold within the part of the casing bound by wall "friction," no vibration would be had unless movement, though ever so light,

were obtained. Should vibration be obtained, it would start faintly with the first slight movement of the casing. This vibration would increase as the pipe became more free. When the vibration was distinct enough to justify the effort, the trip spear would be withdrawn (it will be noted that a bulldog spear could not be withdrawn) and the pipe would be worked with the engine. Movement having been obtained, the success of the operation should be assured, although a repetition of the process might be necessary before the pipe would pull.

Fishing with spear and hydraulic jacks.—If vibration were not obtained and the pipe not freed as described above a pair of hydraulic jacks might be used to assist in loosening the pipe. Each of these jacks is usually capable of lifting 100 tons. They should be placed upon a firm footing, one on each side of the casing, and the ordinary small spider placed over the pipe with an end resting upon each jack. The pipe is then "stretched" to the utmost margin of safety, and the slips inserted in the spider to hold this "stretch." A hold in the pipe is then taken with a trip spear, and jarring up is resumed as formerly described.

The jacks are screwed against the spider in unison with the jarring whenever it is believed that the pipe will stand increased strain. Indications that the pipe has started an upward movement are expected. Certainty that movement has started is known only if vibration is obtained. Unless vibration is obtained, continued jacking will part the casing, but if vibration should be obtained, the jacks may be operated more freely as the vibration increases.

Should the pipe part at a coupling above the spear, because of excessive power applied to the jacks, the pipe could be allowed to remain in the hole until the spear is pulled out. The pipe could then be withdrawn. If a bulldog spear were used, the spear could not easily be withdrawn, and it might be necessary to "strip" all the pipe out over the cable, a long and laborious process compelling the passing of the drilling cable through each stand of pipe as the pipe is withdrawn. Also, cavings would settle upon the bulldog spear when the loose pipe was withdrawn if the wall of the hole was not held by an outside string of casing, at the point where the pipe parted, whereas with a trip spear the mere setting of the pipe together until the hold of the trip spear was broken would be sufficient to exclude the cavings until the spear was pulled out.

Breaking the hold of a "Bull-Dogged" Spear. — When casing spears of any make get "bull-dogged or "fouled" in the pipe, making their removal difficult, the slips can often be worn smooth by "hitching on" so that the jars will hit both ways. If the jars hit both upon the up and down strokes this will start the slips upon the spear to working. Sometimes the slips cut a channel through the heavy steel at the bottom of the spear and drop into the hole, but more often the teeth of the slips are "rasped off" by working the slips up and down against the pipe until they are so smooth that they refuse to catch the pipe. The spear can then be pulled with some difficulty.

A "bull-dogged" spear can also be removed from the hole by running it below the shoe ,and taking a hitch that will cause the slips to strike the shoe on the up stroke. This procedure will cause the slips to shear a passage at the bottom of the spear or break out the dovetails, thus permitting the slips to drop into the hole below. This method is very severe on the shoe, but is effectivetive and can be used as a last resort. Care should be taken to prevent a spear from bull-dogging unintentionally, as complications that may cause a serious fishing job are possible in breaking the hold by the methods just described.

Fishing with Mandrel Substitute, spear, and jacks.—In construction, a mandrel substitute is like a wire-cable socket that no cable hole is bored in, and it has between the wrench squares and the "neck" a thread fitted to a pipe coupling. It is used where a short string of pipe has been left frozen in the bottom of a hole. The top joint of this pipe may be split. The method of use is as follows:

The mandrel substitute is screwed tightly into a pipe coupling of the same size as the lost "string." The neck of the substitute is inside the pipe, and the bottom of the pipe is "plugged" by the substitute. A short stem, or "sinker," long enough to reach below the split (if present) in the top joint of the lost string, is placed upon the mandrel substitute. Either a bulldog or trip spear may be used upon the stem. The use of jars between stem and spear is seldom necessary, and when used the jars frequently cause trouble. Because of the small space in which jars have to operate in this work, and the tendency of a spear to take a lower hold when "knocked" further down a hole, jars are only occasionally an aid in

breaking a hold. Usually a bulldog spear is used without the aid of jars, upon the theory that "something has to come."

Assuming that jars[1] are not used, the tools should now be "strung" as follows: The mandrel substitute is screwed into the coupling, a short stem is screwed into the mandrel substitute, and a spear screwed into the stem.

The pipe with the tools attached, as described, is run into the hole until the spear enters the lost pipe and is below the split, if such exists, in the top joint. The fishing string is then raised and the "stretch" held with a spider placed upon hydraulic jacks. The cable tools are now used. Fishing jars are placed upon the bottom of the stem, and a combination socket with "slips" fitted to the neck of the mandrel substitute is screwed upon the jars. The tools are now run into the pipe and the combination socket takes a hold upon the neck of the mandrel substitute. A hitch is taken with the cable tools and jarring up is commenced. The jacks are operated in unison with the jarring, and the operation is continued until the frozen pipe is freed or parted. As the hold of the combination socket is easily broken when desired, the tools may be withdrawn at will and the pipe pulled with the portion of the lost string jarred loose. The operation can then be repeated. For successful fishing with a mandrel substitute, the walls of the hole must either stand up or be held in place by a protecting string of casing.

Cutting casing in the hole.—When only the lower part of a string of pipe is of service in a hole, the recovery of the unserviceable part of the pipe is often desirable. For example, a hole has 450 feet of 12½-inch pipe within it, 1500 feet of 10-inch pipe has been landed and the water shut off with this string. At 2000 feet the 8-inch pipe freezes and is permitted to remain in place. The well is finished by inserting 2500 feet of 6⅝-inch casing. If the chance of any of the outside strings collapsing or "going bad" is considered slight, the pipe could be cut off near the bottom of each protecting well string and the upper part of the pipe recovered without damage to the hole. The 6⅝-inch pipe could be cut off at 1950 feet and this part recovered, leaving the lower 550 feet in the hole. Such a cut would leave a 50-foot lap of 6⅝-inch pipe extending up into the 8¼-inch. Similarly, 1450 feet of 8¼-inch pipe extending up into

[1]Driving the pipe at the surface to break the hold should trip a trip spear as readily as would the jar.

the 10-inch. After cutting the pipe, either the top of each cut joint in the hole would have to be swaged until it "belled out" tight against the outer string, or else an "adapter" (Fig. 34-f), would have to be placed on the top of the cut joint. The adapter fits over the cut and is prevented from sliding down over the pipe by means of a "shoulder" which rests on the top of the pipe. The top of the adapter is tapered and the outside is flush with the casing through which it is inserted. Were the pipe not "belled out," or an adapter used, the tools would catch on the cut pipe in passing down the hole. When more than one string of pipe is to be cut, each adapter should be set before the next larger string is removed from the hole.

Use of cutters.—The similarity of the various casing cutters now extensively used, making their operation identical. Knives, a (See Fig. 34-g), as in ordinary pipe cutters, varying only in size, are held in sliding steel blocks, b, mounted in a cylindrical steel frame, c. The knives are forced against the pipe by a tapered steel mandrel, d, inserted behind the steel blocks, b, through a hole in the center of the steel frame.

Before "running" the cutter, enough "stretch" should be taken upon the casing and maintained by means of elevators or spider and slips to cause the pipe, when cut in two ,to jump just enough to give notice that the operation has succeeded. This stretching also eliminates the problem of "slack" pipe that would otherwise arise. After the pipe is stretched, the cutter is placed on tubing and run into the hole to the desired depth. A ball-bearing race, though not absolutely essential, should be placed between the elevators and the tubing coupling, immediately above them. This race makes the turning of the tubing less difficult and acts to prevent the tubing from screwing up in the couplings and raising the cutter when the tool is turned.

A set of long-stroke jars small enough to enter the tubing and with a pin of the same size and thread as a sucker-rod pin are placed above the mandrel. From two to four iron sucker rods are placed above the jars. The connected equipment is attached to the sand line, run into the tubing, and permitted to strike lightly upon the cutter, where it will stop. The tubing is then turned by hand power. The weight of the rods above the mandrel forces the blocks containing the knives out against the casing. Sometimes this weight

is sufficient for the work, but when it is not ,and the cutter turns with so little effort as to convince the drillers that it is making litle progress, the jars between the mandrel and sucker rods may be operated by hand, or engine, or by raising and dropping the sand line. When the rods are raised with the sand line and the jars parted without pulling the mandrel out of the cutter, the mandrel drives farther between the sliding blocks each time the rods fall against it and forces the knives farther into the pipe metal and holds them there. The mandrel should not be driven between the blocks too tightly or the tubing can not be turned.

Usually 20 to 40 minutes' turning of the tubing is required to cut the casing. If the casing is not cut after 1½ hours' turning and the tubing is pulled, it will probably be found that the knives were forced too rapidly by the mandrel and were broken. They can then be replaced and the operation repeated. When the casing is cut it will jump from the stress obtained and must be held before running the cutter. The mandrel and rods should then be pulled, the tubing should be raised gently until the cutters are started into the upper pipe and should then be pulled; afterwards the loose casing should be pulled. An adapter (see Fig. 34-f) should then be inserted over the cut joint in the hole or else the top of the joint should be "belled out" with a swage, as formerly described.

Splitting casing in the hole.—Casing splitters[1] are operated by driving down with the drilling tools, with long-stroke jars on the bottom of the stem and the splitter (see Fig. 34-h) attached to the jars.

The simple construction of the splitter makes it a safe and practical tool. The impact of the jars when the tools strike causes a knife, a, in a sliding block, b, which is forced up and against the pipe from the bottom by a mandrel, c, held in place by tension of the string, d, against the pipe, to cut through the pipe. The knife is held stationary in the block, b, by a steel pin, e, extending through the block and the knife. The steel pin also holds the block in the frame of the splitter. Before running the splitter into the casing, the spring, d, is raised up the mandrel by compressing with the fingers the small trigger, g, at the bottom of the mandrel. When the tool is lowered in the hole, there is enough pipe friction upon the

[1]Wagy, E. W., Uses of perforated casing and screen pipe in oil wells: Tech. Paper 247, Bureau of Mines, 1919, p. 9.

spring to prevent its dropping back over the trip trigger. Should the spring lack tension and in some manner drop back while the splitter is being run into the hole, the mandrel would at once raise against the block and a hole would be forced in the pipe by the jars striking.

When the tool is lowered to the desired depth it is then raised, the mandrel draws up through the spring, and the trigger snaps into place. Then the splitter is tripped. The knife will thrust a hole through the pipe with the first impact of the jars. Care must then be taken to keep the jars from "hitting up." Should the jars "hit up," the knife will be withdrawn from the pipe and will probably be broken. After "hitching on" the splitter will drive readily, cutting a slot in the pipe in its progress, until a coupling is reached. The progress of the knife will be retarded by the coupling but not stopped. When the coupling is split, the pipe can then be pulled, although the coupling sometimes fails to spread enough to permit pulling without light driving of the pipe at the top by clamps and drive head.

Uses of casing splitters.—Casing splitters are most commonly used to recover casing when a hole is about to be abandoned, and when the work involved in freeing the pipe, so that the entire string can be recovered, would prove too expensive.

Casing splitters may also be used as perforators to cut holes in casing. Some splitters are constructed with two knives, by the use of which two separate cuts are obtained. Splitters will not always take the place of cutters, as the former are liable to leave the uppermost joint of pipe left in the hole in a split condition, which is undesirable for a hole in which further work is to be done.

A slight stress may be held upon pipe about to be split, but the stress should not be excessive, as the jarring down upon the coupling being cut increases the stress on the upper couplings, and excessive stress can cause the pipe to part above the splitter.

When pipe has collapsed or is so "bad" as to make the redrilling of a hole necessary, if the pipe will not pull, it may be split above the "bad place" more easily than it can be cut and with equally satisfactory results.

In splitting pipe, the wrist pin should be placed in either the first or second hole of the crank shaft in order to avoid breaking the

knife with too forcible a blow. This will also minimize the chances of the jars striking both ways.

Directions For Splicing Wire Rope

The tools required will be a small marline spike, nipping cutters, and either clamps or a small rope sling with which to wrap around and untwist the rope.

In splicing a rope a certain length is used up in making the splice. An allowance of not less than 16 feet for ½-inch rope, and proportionately longer for larger sizes, must be added to the length of your endless rope in ordering.

Having measured carefully the length the rope should be after splicing, and marked the points 6 and 6′, Fig. 35-A, you should unlay the strands from each end of the rope to 6 and 6′, and cut off the hemp center at 6 and 6′, and then—

First.—Interlock the six unlaid strands of each end alternately and draw them eogether so that the points 6 and 6′ meet as shown in Fig. 35-B.

Second.—Unlay a strand from one end and following the unlay closely, lay into the seam or groove it opens, the strand opposite it belonging to the other end of the rope, until within a length equal to three or four times the length of one lay of the rope, and cut the other strand to about the same length from the point of meeting, as shown at 1, Fig. 35-C.

Third.—Unlay the adjacent strand in the opposite direction and following the unlay closely, lay in its place the corresponding opposite strand, cutting the ends as described before at 2, Fig 35-C.

It will be well after each pair of strands to tie them temporarily at the points 1 and 2.

Pursue the same course with the remaining four pairs of opposite strands, stopping each pair about eight or ten turns of the rope short of the preceding pair, and cutting the ends as before.

The strands are now laid in their proper places, with their respective ends passing each other, as shown in Fig. 35-D.

All methods of rope splicing are identical to this point; their variety consits in the method of tucking the ends. The one given below is that most generally practiced.

It now remains to secure the ends:

Clamp the rope either in a vise at a point to the left of 1, Fig.

35-D, and, by a hand clamp applied near 1, open up the rope by untwisting sufficiently to cut the hemp core at 1, and seizing it with the nippers, let your assistant draw it out slowly, you following it closely; crowding the strand in its place until it is all laid in. Cut the hemp core where the strand ends ,and push the end back in its place. Remove the clamps and let the rope close together on it. Draw out the hemp core in the opposite direction and lay the other strand in the center of the rope in the same manner. Repeat the operation at the five remaining points, and hammer the rope lightly at the points where the ends pass eoch other at 1, 1, 2, 2, etc., with small wooden mallets, and the splice is complete, as shown in Fig. 35-E.

If a clamp and vise are not obtainable, two rope slings and short wooden levers may be used to untwist and open up the rope.

A rope spliced as above will be nearly as strong as the original rope and smooth everywhere. After running a few days the splice if well made, cannot be pointed out except by close examination of an expert.

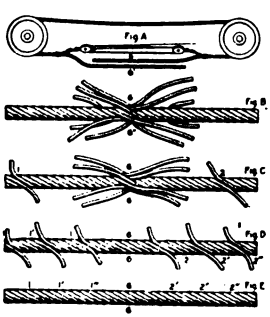


Fig. 35

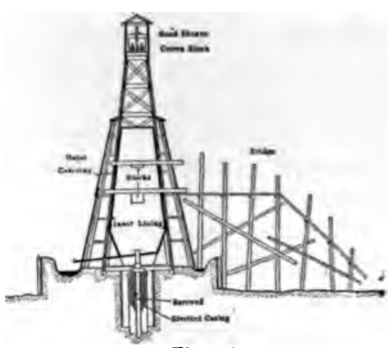


Fig. 36a

Drilling and Production Technique in the Baku Oil Fields[1]

The method of controlling fountains, or gushers, is the result of growth, along with the Russian system of drilling, where large diameters and riveted casing have been in vogue. The screw casing is seldom used except to exclude water. Formerly the method of finishing wells and the condition of the casing at the top of the well would not permit the use of gates, manifolds and connections as is standard elsewhere.

[1]Arthur Knapp in Transactions Am. Inst. Min & Met. Engrs., Jan. 1920.

The life of the flowing wells is very short, particularly those 10 inches or more in diameter, which produce large quantities of sand and often flow for but a few days and are then a complete loss. More than 1,000,000 poods in twenty-four hours have been claimed in several instances, but in no case was the flow for more than a few days.

The oil sands of this district are free uncemented sands and vary in thickness from paper thin to a maximum of 10 feet (3m.) The sands are interlaid with strata of soft clay. In spite of this, the practice has been to drill into such sands and produce from the open hole without screen or liners. Sometimes the casing is set below the oil sand but in this case holes from 2½ to 3 inches in diameter are drilled opposite the oil sand, which would not have the effect of a screen.

Fig 36-a is an outline of the fountain shield ready for the control of a fountain. It is composed of an inner and an outer covering made from rough boards. The framework is made of rough round poles. When a light flow is expected, only the inner lining is built; when the fountain comes in unexpectedly, it is often possible to build only the outer cover. The bridge is for the purpose of renewing the blocks as they become worn by the flow. The lower block, as here shown, is made of hardwood and is bolted to the crossbeams with brass bolts. The grain end is toward the flow. The upper block, as shown here, is made of cast steel and is also bolted to the crossbeam with brass bolts. Both blocks may be wood or steel, depending on the fancy of the engineer in charge.

Valves, tees and lead lines are sometimes put on the well to prevent its flowing before the shield is complete and to control the well in case of fire. No attempt is made to control the production or to direct the flow when the well is put to producing; the well is always allowed to flow to capacity against the blocks. Usually the valves are cut out and rendered useless soon after the flow commences. The wear of the blocks depends on the flow; sometimes they must be renewed daily. This arrangement of fountain control is not always effective. The top of the derrick, blocks and all, is sometimes lifted entirely off and the well flows wild until it sands up or the flow has weakened sufficiently to allow the blocks to be replaced. The derricks are usually set on embankments from 6 to 10 feet high, these embankments being reinforced

with pilings lined with planks. This bank is necessary to allow the oil to flow away from the well and to give space for the handling of the large amount of sand that some of the wells produce.

Fig. 36-b is an exact copy of the record of six wells in the Balachany field. It shows the average condition of producing wells

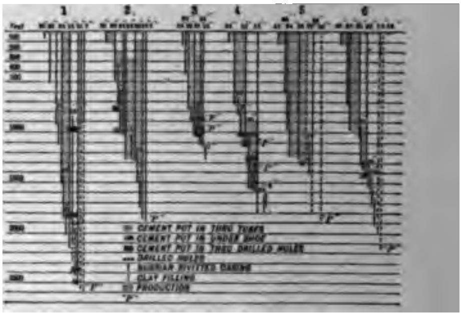


Fig. 36b

drilled by the Russian method. In general, the formation to 1100 feet is clay, shale and sandy shale. Below 1100 feet there is also soft limestone, soft sandstone and hard shale. There are no thick layers of hard rock. Sand, entirely uncemented, is seldom found except in thin layers between layers of shale.

The Russian riveted casing is far from water-tight, which accounts for the large amount of cement put in around the casing. Sometimes it is necessary to fill the casing with clay before the liquid cement will remain behind the casing long enough to set. The cement is put in with a pump, 1 or 1½-inch pipes being inserted between the casings to convey it to its place.

The Russian method of drilling makes use of steel poles to actuate the tools but differs from the Canadian system, which also used poles of wood or iron, in that a "free-fall" is used above the tools instead of the tools dropping with the rods. This free-fall picks up the tools at the bottom of the stroke and releases them at the top of the stroke, allowing them to fall free to the bottom of the hole. Thus the fall is limited to the length of the stroke of the walking beam and differs from the American cable tool system where the fall, due to the elasticity of the drilling cable, may be several times the stroke of the beam.

The Russian drilling machine is a slow ponderous machine,

very heavy and very hard to handle, transport, and install. The large starting diameters are necessary because of the large number of strings of casing used and the large oil string necessary for producing by bailing. Also, there are several producing horizons,

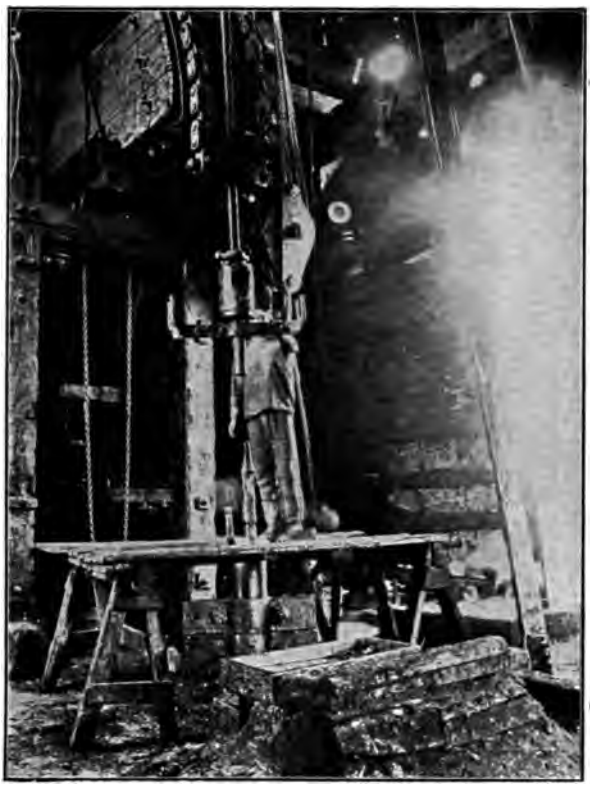


Fig. 36c—Interior of derrick showing end of walking beam and temper-screw.

and wells are drilled large into the first horizon so that later they may be deepened. Casing, both Russian riveted and screwed, is lowered by means of clamps somewhat on the style of the American casing clamp. The Russians have never developed nor learned to use elevators, spiders and slips, casing tongs, or other modern oil well tools, except when these tools have been brought in with American machinery and used by American drillers. The casing is always carried with the tools in the Russian system. The bit

is seldom advanced more than 20 feet beyond the shoe. Underreaming is practiced to a large extent.

Mr. Knapp submits a drilling record of one well drilled to 1687 feet which took 730 days distributed as follows:

Days at work	730
Days of drilling	128 or 18.2%
Days lowering casing	98 or 14.0%
Days idle	28 or 0.4%

(Does not include 60 days spent in bringing well in.)

Average advance per day of actual drilling, 13.2 feet.

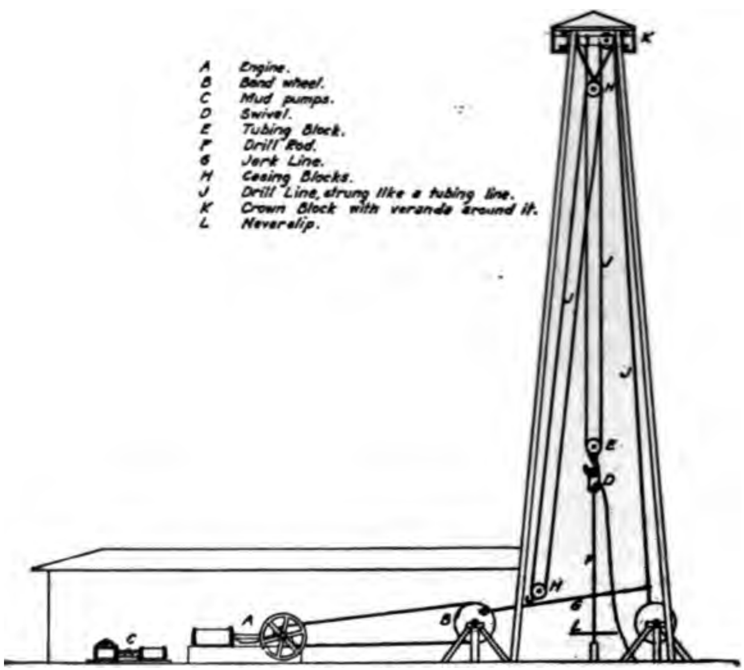


Fig. 37—Roumanian Well Drilling Outfit.

Method of Drilling in Roumania

The common method of drilling wells in the Filipesti field in Roumania is described in a communication addressed to the author from Mr. Carl Tresfon, an employe of the Astra Romana. The Pennsylvanian, Rotary, Canadian and Astra Spielung systems are

in use but the Canadian and Astra systems are most common. (See Fig. 37.)

A very large drilling engine is used to drive a 5-foot band wheel. The bull wheels are driven off of the band wheel with chain transmission instead of using bull ropes. Hollow drill rods are used instead of drilling cable and these are connected with a rotary swivel so that mud is kept circulating as drilling proceeds. While drilling is going on a man on the derrick floor is constantly employed in turning the rods with a casing pole and neverslips. This imparts the necessary turning motion to the drill. The drilling tools are suspended from a heavy tubing line and block and get their up and down motion from a jerk line attached to the crank somewhat as shown in the attached drawing. It usually takes about one and one-half days to pull out and change the bit and this is done about once a week.

In running casing they use, ordinarily, two six-sheave casing blocks. Inserted joint casing is used most commonly and hence no elevators can be employed. This makes the operation of landing a string of casing a very slow and tedious job.

The whole derrick is boarded in against the severe weather and to save production. When the well flows they use a large cast iron bell weighing six or seven tons. This is hung over the hole.

The average progress while drilling is around 30 feet in twenty-four hours.

BILLS OF MATERIAL FOR DERRICKS AND STANDARD RIGS

Rotary Derricks

72 FEET HIGH, 22 FEET BASE

4 pieces 10x10 in. x 22 ft. for sills	2 pieces 1x12 in. x 12 ft. for girts
10 pieces 2x12 in. x 22 ft. for floor joists	1 piece 1x12 in. x 16 ft. for girts
35 pieces 2x 8 in. x 22 ft. for floor	8 pieces 1x 6 in. x 20 ft. for braces
4 pieces 2x12 in. x 40 ft. for legs	8 pieces 1x 6 in. x 18 ft. for braces
4 pieces 2x12 in. x 34 ft. for legs	8 pieces 1x 6 in. x 16 ft. for braces
4 pieces 2x10 in. x 40 ft. for legs	8 pieces 1x 6 in. x 14 ft. for braces
4 pieces 2x10 in. x 34 ft. for legs	8 pieces 1x 6 in. x 12 ft. for braces
4 pieces 2x12 in. x 20 ft. for girts	4 pieces 1x 6 in. x 18 ft. for braces
4 pieces 2x12 in. x 18 ft. for girts	4 pieces 1x 6 in. x 14 ft. for braces
4 pieces 2x12 in. x 16 ft. for girts	1 piece 2x12 in. x 12 ft. for pulley blocks
4 pieces 2x12 in. x 14 ft. for girts	2 pieces 4 x4 in. x 10 ft. for pulley blocks
4 pieces 2x12 in. x 12 ft. for girts	144 lineal ft. 2 in. x 4 in. for ladder
4 pieces 1x12 in. x 10 ft. for girts	144 lineal ft. 1 in. x 4 in. for ladder
2 pieces 1x12 in. x 16 ft. for girts	Total, 4625 feet. 100 lbs. nails.

Estimated weight, 18,000 lbs.

106 FEET HIGH, 24 FEET BASE

6 pieces 10x10 in. x 26 ft. for bottom sills
8 pieces 8x10 in. x 26 ft. for top sills
8 pieces 2x12 in. x 24 ft. for foundation
24 pieces 2x12 in. x 24 ft. for floor [blocks
4 pieces 2x12 in. x 24 ft. extension for [pumps
4 pieces 2x12 in. x 18 ft. for starting legs
22 pieces 2x12 in. x 16 ft. for legs
4 pieces 2x12 in. x 20 ft. for legs
24 pieces 2x10 in. x 16 ft. for legs
56 pieces 2x10 in. x 16 ft. for doublers
2 pieces 2x10 in. x 26 ft. for V board
4 pieces 2x12 in. x 24 ft. for girts
4 pieces 2x12 in. x 22 ft. for girts
4 pieces 2x12 in. x 20 ft. for girts
8 pieces 2x12 in. x 18 ft. for girts
20 pieces 2x12 in. x 16 ft. for girts
10 pieces 2x 8 in. x 24 ft. for braces
8 pieces 2x 8 in. x 22 ft. for braces
16 pieces 2x 8 in. x 20 ft. for braces
8 pieces 2x 6 in. x 18 ft. for braces

16 pieces 2x 6 in. x 16 ft. for braces
8 pieces 2x 6 in. x 14 ft. for braces
16 pieces 2x 6 in. x 12 ft. for braces
8 pieces 2x 6 in. x 10 ft. for braces
8 pieces 2x10 in. x 20 ft. for top
3 pieces 5x 5 in. x 16 ft. for gin pole
12 pieces 2x 4 in. x 16 ft. for ladder
10 pieces 1x 4 in. x 16 ft. for ladder
4 pieces 1x 6 in. x 16 ft. for ladder
3 pieces 3x12 in. x 24 ft. for head board to [set up hoists
2 pieces 2x12 in. x 22 ft. for swivel boards
2 pieces 2x12 in. x 20 ft. for double boards
2 pieces 2x12 in. x 16 ft. for triple boards
2 pieces 2x12 in. x 12 ft. quadruple b'ds
4 pieces 2x10 in. x 16 ft. for finger boards
Total, 11,780 feet
100 lbs. 30d nails
200 lbs. 20d nails
50 lbs. 10d nails

Estimated weight, 45,550 lbs.

88 FEET HIGH, 22 FEET BASE

10 pieces 8x10 in. x 22 ft. for sills
4 pieces 2x10 in. x 18 ft. for starting legs
4 pieces 2x 8 in. x 20 ft. start & stop legs
6 pieces 2x10 in. x 24 ft. for bottom doublers [and V boards
45 pieces 2x10 in. x 16 ft. for legs and girts
60 pieces 2x 8 in. x 16 ft. for legs & doublers
8 pieces 2x12 in. x 20 ft. for first set girts [and swivel boards
26 pieces 2x12 in. x 22 ft. for floor
9 pieces 2x 6 in. x 22 ft. for braces

8 pieces 2x 6 in. x 20 ft. for braces
8 pieces 2x 6 in x 18 ft. for braces
16 pieces 2x 6 in. x 16 ft. for braces
8 pieces 2x 6 in. x 14 ft. for braces
16 pieces 2x 6 in. x 12 ft. for braces
8 pieces 1x 6 in. x 16 ft. for braces, etc.
10 pieces 2x 4 in. x 16 ft. for ladder
7 pieces 1x 4 in. x 16 ft. for ladder strips
8 pieces 2x10 in. x 20 ft. for derrick top
3 pieces 4x 4 in. x 14 ft. for gin poles
Total, 7500 feet. 150 lbs. nails.

Estimated weight 29,000 lbs.

LOUISIANA TYPE

112 FEET HIGH, 24 FEET BASE

16 pieces 8x10 in. x 24 ft. for sills
44 pieces 2x12 in. x 24 ft. for floor, starting legs, extension for pumps, foundation blocks
5 pieces 2x12 in. x 22 ft. for first girts
4 pieces 2x10 in. x 20 ft. for girts
60 pieces 2x10 in. x 16 ft. for girts and legs
6 pieces 2x12 in. x 20 ft. for legs
12 pieces 2x10 in. x 18 ft., legs & doublers
74 pieces 2x 8 in. x 16 ft., legs & doublers
8 pieces 2x 8 in. x 22 ft. for doublers
6 pieces 2x10 in. x 24 ft. for doublers
8 pieces 2x 8 in. x 24 ft. for braces
4 pieces 2x 8 in. x 20 ft. for braces
17 pieces 2x 6 in. x 20 ft. for braces

8 pieces 2x 6 in. x 18 ft. for braces
16 pieces 2x 6 in. x 16 ft. for braces
16 pieces 2x 6 in. x 14 ft. for braces
17 pieces 2x 6 in. x 12 ft. for braces
8 pieces 1x 6 in. x 16 ft. for braces and top
3 pieces 6x 6 in. x 14 ft. for gin pole
14 pieces 2x 4 in. x 16 ft. for ladder
10 pieces 1x 4 in. x 16 ft. for ladder
2 pieces 3x12 in. x 24 ft. hoist headboards
8 pieces 1x12 in. x 16 ft. extra
Total, 11,274 feet
100 lbs. 30d nails
200 lbs. 20d nails
25 lbs. 10d nails

Estimated weight, 38,000 lbs.

ENGINE FOUNDATION

2 pieces 16 in. x 18 in. x 14 ft. mud sills
2 pieces 16 in. x 16 in. x 12 ft. pony sills
2 pieces 8 in. x 24 in. x 9 ft. split block

4—3/4 in. x 24 in. machine bolts and washers
2—7/8 in. x 11 ft. d.e. bolts, washers & nuts
1 piece 1 in. x 4 in. x 2 10-12 ft. steel plate

Cable Tool Rigs.

Rigs for drilling wells in North Texas.—For drilling in the North Texas deep cable tool territory where very long strings of pipe are used a very heavy rig is absolutely necessary. Almost

everyone is using for this purpose an 84-foot derrick with a 22-foot base. For the deep territory of Young and northern Stephens County the derricks should all be twin-legged, and the legs should be doubled to the top of the rig. These rigs should also be sway-braced. However, sway-bracing is not necessary in the territory where the wells are not to be drilled to a greater depth than 3000 feet, such as Desdemona.

The following is a complete bill of material for an 84x22-foot sway braced rig:

PINE LUMBER.

Pieces	Dimensions in. in. ft.	Board Feet
25	2x12x22	1100
10	2x10x20	333
30	2x12x20	1200
18	2x 8x20	480
16	2x12x18	576
12	2x 6x20	240
30	2x 6x16	480
16	2x 6x14	224
30	2x 4x16	320
10	2x 4x12	80
16	2x 8x18	341
20	1x 6x16	160
100	2x12x16	3200
45	2x10x16	1200
75	2x 8x16	1602
100	1x12x16	1600
50	1x12x18	900
50	1x12x20	1000
70	1x12x14	980
70	1x12x12	840
2	4x 4x16	43
		16,899

EXTRA FOR SWAY-BRACING

Pieces	Dimensions in. in. ft.	Board Feet
16	2x10x22	588
18	2x10x20	600
12	2x10x16	320
8	2x 8x20	292
8	2x 8x18	213
8	2x 8x16	171
		1,790

PINE TIMBERS

Pieces	Dimensions in. in. ft.	Board Feet
1 Beam	14x24x24	824
1 Main sill	16x16x28	765
1 Sub sill	16x16x16	341
1 Sampson post	16x16x16	341
4 Mud sills	16x16x18	1536
3 Mud sills	16x16x14	896
4 P. & C. sills	12x12x12	576
1 Reel sill and post	12x12x18	216
1 Bunting pole	6x 8x22	88
4 Braces	6x 8x14	224
4 Braces	6x 8x16	256
2 Side sills	10x10x24	400
6 Derrick sills	8x10x22	880
2 Engine blocks	10x20x10	267
4 Casing rack	8x 8x20	426
		8056

OAK TIMBERS

Pieces	Dimensions in. in. ft.	Board Feet
1 Jack post	14x16x14	261
2 Crown blocks	6x16x16	256
1 Bull shaft	18x18x14	378
1 Swing lever	8x10x10	67
4 B. & C. posts	12x12x12	576
1 Pitman	5x12x12	60
1 Bumber	8x10x12	80
1 Calf wheel shaft	18x18x 6	128
8 Keys	3x 5x14	105
		1911

Total number board feet pine lumber. 26,745
Total number board feet oak lumber.. 1,911

Total number board feet for rig.... 28,656

This list does not include lumber for boarding up cellar. Cellars vary in depth from 4 feet to 30 feet. Most operators drilling in a country where much under-reaming is to be done, like a cellar about 20 feet deep and 8x10 feet in area. It is customary to

board the cellar up with 2-inch lumber and to stand a 10x10-inch timber in each corner.

Rig irons.—With the above outlined bill of lumber for a rig there should be furnished 6-inch rig irons such as are marketed by all of the large oil well supply companies. One hears numerous arguments as to the respective merits of Oklahoma and California pattern rig irons. However, by far the greater number of rigs being built at present are using the California pattern, or Ideal, rig irons, and there is no question but what they are giving the best service. For deep wells (3500 feet and over) the sand reel shaft should be 5-inch in diameter and 9 feet long or the great weight of sand line carried is apt to spring it. The 6-inch by 10-foot sand reel shaft with double brake wheel is slowly coming into use for extra deep territory where much bailing is necessary.

The chain-driven calf wheel is universally employed and it is only rarely that the old rope-driven calf wheels are seen.

It is the opinion of the writer that, in the Desdemona pool, where very few wells reach a depth of over 2750 feet and no very long strings of pipe are handled, lighter and cheaper rigs would do the work just as well as the present heavy ones. There is no reason why a standard Cushing rig with 72-foot derrick, no sway braces, and with 5-inch rig irons will not do the work satisfactorily.

Steel bull wheels and calf wheels.—Where drilling is carried to a greater depth than 3500 feet and wooden calf and bull wheels are used, one usually sees about three sets of bull wheels and possibly two worn-out calf wheels lying out back of the rig before the well is finished. All of the larger companies are now using steel bull and calf wheels. One of these wheels will drill eight or ten wells with only a relining of the brake being necessary. The steel bull wheels have a double pressed steel tug rim and a wood-lined brake wheel with 10-inch face. These wheels are usually 8 feet in diameter.

Steel band wheels are also being tried out by some of the larger companies and they are proving very satisfactory. Some of the companies are using steel bull and calf wheel shafts with 3x12-inch wooden arms which bolt on. These are quite an improvement over the wooden wheels but the wooden tug rim on the bull wheels is very prone to wear out after drilling a well or so.

Imperial Ideal Rig[1]

Timber and Lumber Required to Build a Complete Rig Derrick 82 Feet High, Base 20 Feet Square

The sizes of timbers may be varied depending upon the relative strength of the material as compared with the strength of the timbers listed below:

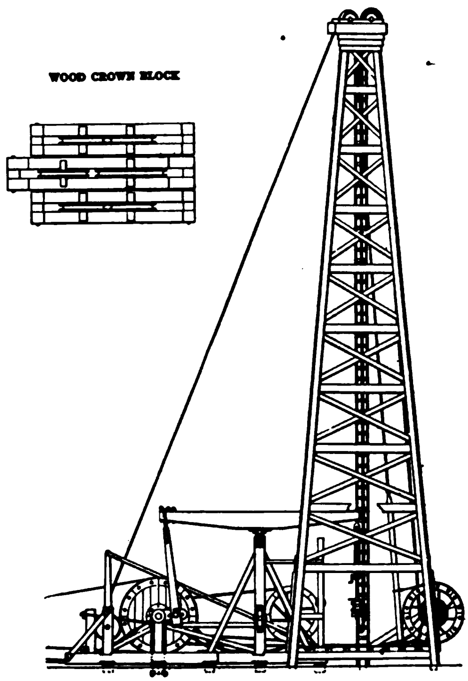


Fig. 38—Imperial Ideal Rig.

FOR MAIN FOUNDATION

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
1	1	16x16	30	Main sill	Oregon pine
2	1	16x16	20	Sub sill	Oregon pine
3	2	16x16	6	Jack posts	Oregon pine
4	1	16x16	12	Tail sill	Oregon pine
5	1	16x16	16	Sampson post	Oregon pine
6-7	2	16x16	6	Knuckle and tail post	Oregon pine
8	1	16x16	5	Back brake	Oregon pine
9	1	6x 8	10	Back brake support	Oregon pine
10	1	14x30	26	Walking beam	Oregon pine
11-12	2	6x 6x16	14	Pitman and swing lever	Oregon pine

[1]Courtesy Oil Well Supply Co.

FOR MAIN FOUNDATION.—Continued.

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
13	1	2x14	5	Top of beam	Oak
14	4	16x16	16	Mud sills	Redwood
15	1	14x14	14	Nose sills	Redwood
16	5	3x12	22	For under mud sills	Redwood
	24	2½x4-4x4	22	Keys for rig	Oregon pine
18	1	6x 6	30	Bunting pole	Oregon pine
				FOR ENGINE HOUSE	
19	2	16x16	16	Mud sills	Redwood
20	2	14x14	12	Pony sills	Oregon pine
21	1	24x24	9	Engine block	Oregon pine
	2	2x 6	12	Frame	Oregon pine
	3	2x 6	14	Frame	Oregon pine
	2	2x 4	14	Frame	Oregon pine
	2	2x 4	12	Frame	Oregon pine
	12	1x10	14	Flooring	Oregon pine
	64	1x10	8	Flooring siding	Oregon pine
	4	1x10	12	Flooring gables	Oregon pine
	2	1x10	10	Flooring gables	Oregon pine
	2	1x 6	16	Flooring gables	Oregon pine
	17	1x10	16	Roofing	Oregon pine
	16	1x 6	16	Roofing	Oregon pine
				FOR BELT HOUSE	
	1	2x10	26	Bottom plate	Oregon pine
	1	2x10	22	Bottom plate	Oregon pine
	5	2x 6	26	Top plate	Oregon pine
	2	2x 6	20	Top and brace	Oregon pine
	1	4x 6	16	Brace	Oregon pine
	30	1x10	10	Siding	Oregon pine
	30	1x10	12	Siding	Oregon pine
	5	1x10	12	Flooring	Oregon pine
	5	1x10	14	Flooring	Oregon pine
	5	1x10	16	Flooring	Oregon pine
	30	1x10	9	Roofing	Oregon pine
	20	1x10	6	Roofing	Oregon pine
	20	1x 6	6	Roofing	Oregon pine
	30	1x 6	9	Roofing	Oregon pine
				FOR DERRICK	
22	2	8x10	22	Side sills	Oregon pine
23	7	8x 8	20	Sills	Oregon pine
24	40	3x12	5	Blocking for corner under dk.	Redwood
25	16	3x12	4	Blocking for corner under dk.	Redwood
26	4	14x14	4	Blocking for corner under dk.	Redwood
27	2	12x12	16	Casing sills under dk.	Redwood
28	25	2x12	20	Flooring	Oregon pine
	16	2x12	18	Girts	Oregon pine
	5	2x12	20	Water table and top	Oregon pine
	4	2x10	18	Bottom legs	Oregon pine
	4	2x 8	26	Bottom legs	Oregon pine
29	16	2x 8	16	Legs	Oregon pine
29	60	2x10	16	Legs and doubler	Oregon pine

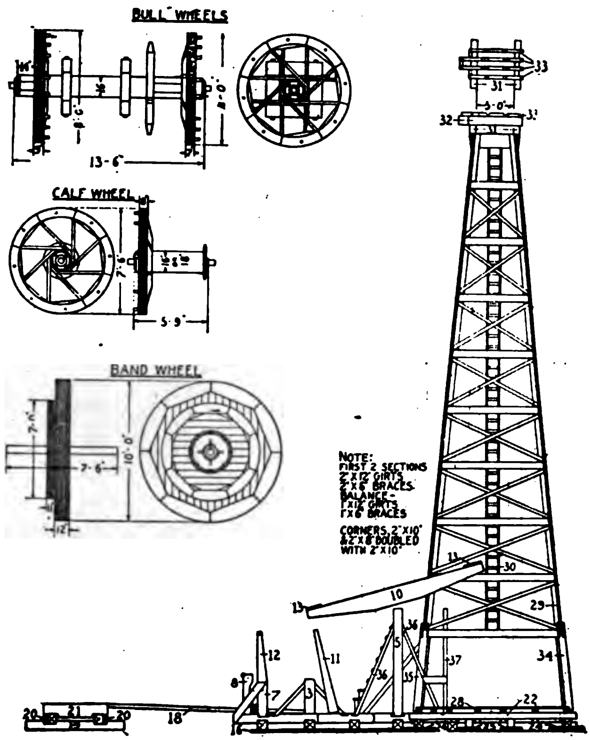


Fig. 39—Imperial Ideal Rig Construction Plan.

FOR DERRICK.—Continued.

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
29	8	2x10	24	Doubler	Oregon pine
30	20	2x 4	16	Ladder	Oregon pine
	30	1x12	16	Girts	Oregon pine
	60	1x 6	16	Braces and ladder strip	Oregon pine
	8	2x 6	20	Braces and ladder strip	Oregon pine
	8	2x 6	18	Braces and ladder strip	Oregon pine
	2	4x 6	16	Roof stringers	Oregon pine
31	2	10x12	7	Top bumper	Oregon pine
32	2	6x16	16	Crown block	Oregon pine
33	2	6x 6	12	Crown block	Oak
	20	1x10	14	Roofing	Oregon pine
	6	1x10	20	Roofing	Oregon pine
	20	1x 6	16	Battens	Oregon pine
	20	1x 6	14	Battens	Oregon pine
	16	1x10	20	Forge house	Oregon pine
	16	1x10	14	Forge house	Oregon pine
	30	1x10	20	Siding	Oregon pine
	1	8x 8	16	Crane post	Oregon pine
	3	6x 6	16	Blocking	Redwood
	20	1x10	16	Roofing	Oregon pine

FOR BULL WHEELS

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
34	2	12x12	11	Posts	....
	1	16x16	14	Shaft	Oak
	4	2½x12	18	Arms—Surfaced 4 sides	....
	8	2½x 8	8	Cants—Plain	....
	16	2½x 8	8	Cants—V-grooved	....
	88	1x 8	8	Cants—Plain	....
	32	1½x 9	..	Hardwood pins	....
	1	4x 6	14	Brace	....
	21	1x10	16	House	....
	3	1x 6	16	House	....
	5	1x10	10	House	....

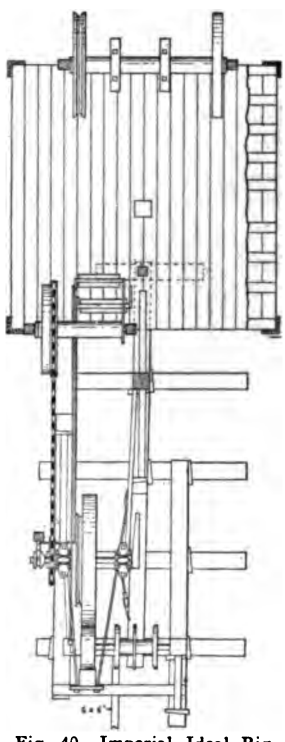


Fig. 40—Imperial Ideal Rig Alignment of Working Parts

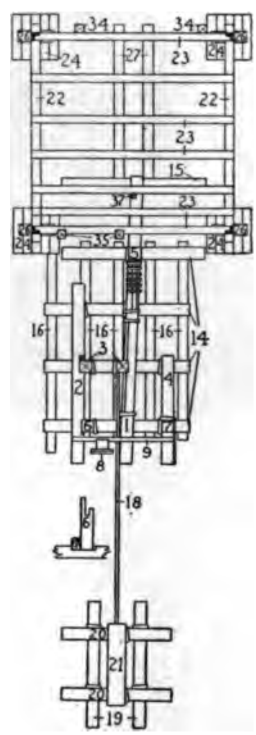


Fig. 41—Imperial Ideal Rig Construction Plan.

CALF WHEELS

	1	18x18	6	Shaft	Oak
35	2	12x12	12	Posts	....
	2	2½x12	16	Arms—Surfaced 4 sides	....
	8	2½x 8	7½	Cants	....
	48	1x 8	7½	Cants—Surfaced 1 side	....

BAND WHEEL

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
	22	2x12	16	Lumber for bank wheel surfaced on 1 side	.. ..
	24	2x 8	10	Cants—Plain	....
	8	2½x 8	7	Cants—Plain	....
	16	2½x 8	7	Cants—V-grooved	....
	24	1x 8	7	Cants—Plain	....

ADDITIONAL

36	2	6x 8	16	Braces for samson post	Oregon pine
37	1	6x 8	16	Headache post	Oregon pine
	6	4x 6	20	Stringer for walk & braces	Oregon pine
	5	4x 6	18	Stringer for walk & braces	Oregon pine
	2	6x 8	20	Casing rack	Oregon pine
	5	4x 6	8	For walk	Oregon pine
	14	2x12	20	For walk	Oregon pine
	8	2x12	20	Sump boxes	Oregon pine

300 feet extra 1-inch by 16-foot pine for rigging up.

Combination Rig[1]

Timber and Lumber Required to Build a Complete Combination Rig Derrick 106 Feet High, Base 24 Feet Square

The sizes of timbers may be varied depending upon the relative strength of the material as compared with the strength of the timbers listed below:

FOR MAIN FOUNDATION

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
1	1	16x16	30	Main sill	Oregon pine
2	1	16x16	20	Sub sill	Oregon pine
3	1	16x16	12	Tail sill	Oregon pine
4	1	16x16	16	Samson post	Oregon pine
5	2	16x16	6	Jack posts	Oregon pine
6-7	2	16x16	6	Knuckle and tail posts	Oregon pine
8	1	16x16	5	Back brake	Oregon pine
8	1	6x 8	12	Back brake support	Oregon pine
9	1	14x30	26	Walking beam	Oregon pine
10-11	2	6x6x6x16	14	Pitman and swing lever	Oregon pine
12	1	2x14	5	For ends of beam	Hardwood
13	1	6x 6	30	Hunting pole	Oregon pine
13	32	2½x4-4x 4	22	Keys	Oregon pine
15	4	16x16	16	Mud sills	Redwood
16	1	14x14	14	Nose sill	Redwood
17	5	3x12	22	For under mud sills	Redwood

FOR DERRICK

18	2	12x12	26	Side sills	Oregon pine
19	8	10x12	24	Sills	Oregon pine
20	24	3x12	6	Blocking for corners	Redwood
21	20	3x12	5	Blocking for corners	Redwood
21	16	3x12	4	Blocking for corners	Redwood

[1]Courtesy Oil Well Supply Co.

FOR DERRICK.—Continued.

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
23	4	14x14	4	Blocking	Redwood
24	2	14x14	18	Casing sills	Redwood
24	2	8x10	20	Posts	Redwood
26	30	2x12	24	Derrick floor	Oregon pine
27	12	2x12	24	Girts	Oregon pine
27	16	2x12	22	Girts	Oregon pine
27	12	2x12	20	Girts	Oregon pine
27	12	2x12	18	Girts	Oregon pine
27	12	1½x12	18	Girts	Oregon pine
27	42	1½x12	16	Girts	Oregon pine
..	5	2x12	20	Top and water table	Oregon pine
29	4	2x12	20	Bottom legs	Oregon pine
29	4	2x10	26	Bottom legs	Oregon pine
29	29	2x10	16	Legs	Oregon pine
29	35	2x12	16	Legs	Oregon pine
29	12	2x12	24	Doublers	Oregon pine
29	12	2x12	18	Doublers	Oregon pine
29	29	2x12	16	Doublers	Oregon pine
31	16	2x 4	16	Ladder	Oregon pine
32	60	1½x 6	16	Braces and ladder strip	Oregon pine
33	16	2x 6	18	Braces	Oregon pine
33	16	2x 6	20	Braces	Oregon pine
33	16	2x 6	22	Braces	Oregon pine
34	16	2x 6	24	Braces	Oregon pine
..	16	2x 6	16	Sway bracing	Oregon pine
..	16	2x 6	18	Sway bracing	Oregon pine
..	16	2x 6	20	Sway bracing	Oregon pine
..	16	2x 6	22	Sway bracing	Oregon pine
..	16	2x 6	24	Sway bracing	Oregon pine
..	16	2x12	18	Sway bracing	Oregon pine
..	16	2x12	20	Sway bracing	Oregon pine
..	16	2x12	22	Sway bracing	Oregon pine
..	2	6x 6	22	Roof rollers	Oregon pine
..	2	4x 6	20	Roof stringers	Oregon pine
35	2	6x18	16	Crown block	Oregon pine
36	2	6x16	12	Crown block	Oak
37	4	12x12	7½	Bumpers for crown block	Oregon pine
..	50	1x10	14	Roof	Oregon pine
..	10	1x10	20	Roof	Oregon pine
..	50	1x10	16	Roof	Oregon pine
..	30	1x10	22	Pump shed siding	Oregon pine
..	25	1x10	24	Pump shed siding	Oregon pine
38	2	6x 8	16	Samson post braces	Oregon pine
38	1	6x 8	16	Headache post	Oregon pine
38	1	5x 8	16	Crane post	Oregon pine
40	16	2x 6	26	Sway bracing	Oregon pine
41	1	8x 8	24	Rotary girt	Oregon pine

FOR ENGINE HOUSE

42	2	16x16	16	Mud sills	Redwood
..	2	3x12	16	Under mud sills	Redwood
44	2	14x14	14	Pony sills	Oregon pine
45	1	24x24	9	Engine block	Oregon pine
..	6	2x 6	16	Frame	Oregon pine
..	6	2x 4	16	Frame	Oregon pine

FOR ENGINE HOUSE.—Continued.

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
..	20	1x10	16	Flooring	Oregon pine
..	64	1x10	8	Siding	Oregon pine
..	4	1x10	16	Gables	Oregon pine
..	4	1x10	12	Gables	Oregon pine
..	40	1x10	10	Roofing	Oregon pine
..	24	1x 6	10	Battens	Oregon pine

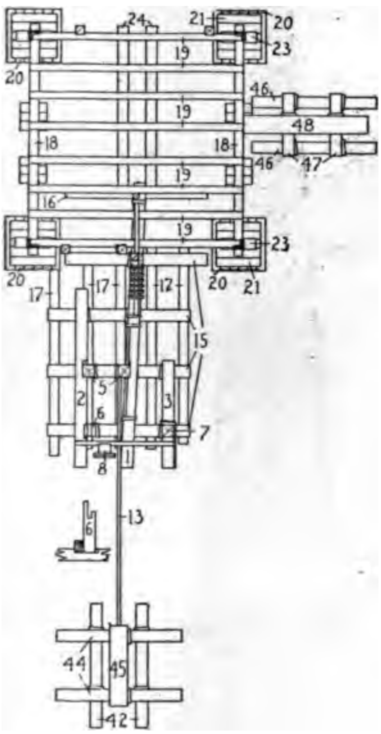


Fig. 42—Combination Rig Construction Plan.

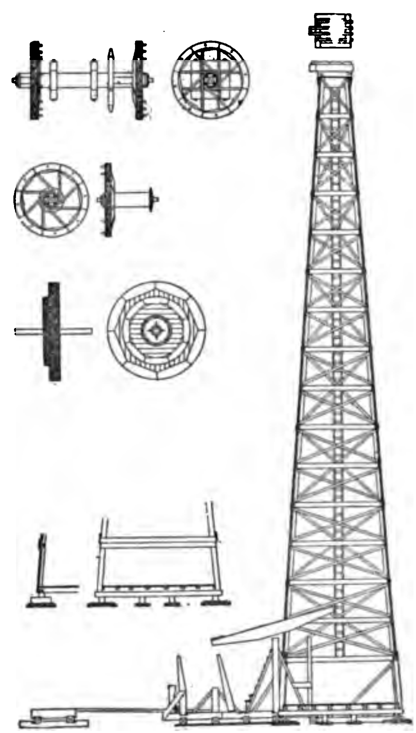


Fig. 43—Combination Rig Construction Plan.

FOR BELT HOUSE

..	2	2x10	26	Bottom plate	Oregon pine
..	1	2x10	22	Bottom plate	Oregon pine
..	5	2x10	26	Stringers	Oregon pine
..	2	2x10	20	Stringers and brace	Oregon pine
..	80	1x10	10	Siding and roofing	Oregon pine
..	30	1x10	12	Siding and roofing	Oregon pine
..	5	1x10	24	Siding and roofing	Oregon pine
..	10	1x10	12	Siding and roofing	Oregon pine
..	5	1x10	16	Siding and roofing	Oregon pine
..	40	1x10	8	Roofing	Oregon pine

FOR BELT HOUSE.—Continued.

Illustration		Size,	Length,		
..	40	1x10	16	Roofing	Oregon pine
..	20	1x 6	16	Roofing battens	Oregon pine
..	20	1x 6	10	Roofing battens	Oregon pine

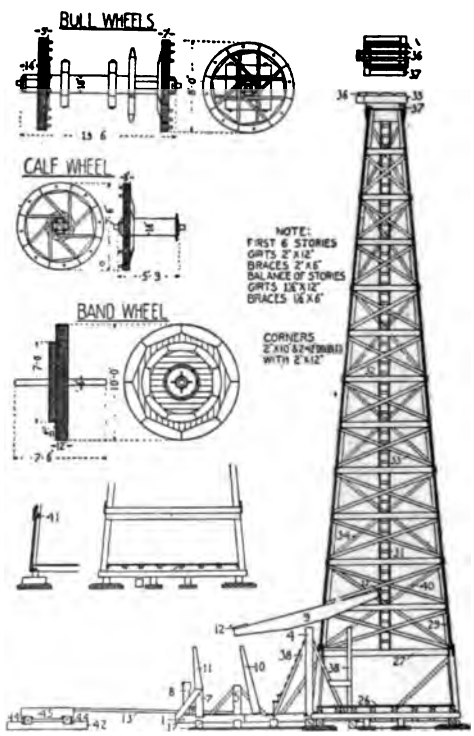


Fig. 44—Combination Rig Construction Plan.

FOR ROTARY ENGINE FOUNDATION

46	2	16x16	16	Mud sills	Redwood
..	2	3x12	16	Under mud sills	Redwood
47	2	14x14	8	Pony sills	Oregon pine
48	1	24x24	14	Engine block	Oregon pine

BULL, BAND AND CALF WHEELS

Same as shown in specifications of 82-foot Imperial Ideal Rig on page 15.

ADDITIONAL

..	25	2x12	24	Sump boxes	Oregon pine
..	16	1x 6	16	Sump boxes	Oregon pine
..	6	4x 6	20	Stringers for walk and braces	Oregon pine

ADDITIONAL.—Continued.

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
..	5	4x 6	18	Stringers for walk and braces	Oregon pine
..	5	4x 6	8	For walk	Oregon pine
..	14	2x12	20	For walk	Oregon pine
..	2	6x 8	20	Casing rack	Oregon pine

500 feet extra of 1-inch by 16-foot Oregon pine

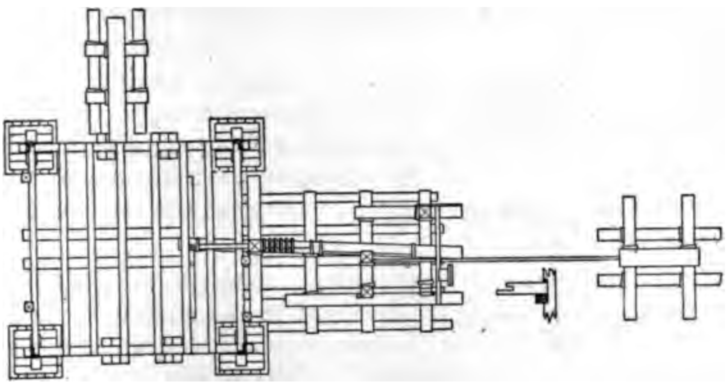


Fig. 45—Combination Rig Construction Plan.

Timber and Lumber Required To Build a Complete Combination Rig Derrick 122 Feet High, Base 24 Feet Square

Use specifications for 106-foot rig with the addition of the following:

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
27	4	1½x12	16	Girts	Oregon pine
29	2	2x10	16	Legs	Oregon pine
29	4	2x12	16	Doublers	Oregon pine
32	16	1½x 6	16	Braces for derrick and ladder step	Oregon pine

Derrick 130 Feet High, Base 24 Feet Square

Use specifications for 106-foot rig with the addition of the following:

Illustration No.	Pieces	Size, inches	Length, feet	Name	Kind of wood
27	8	1½x12	16	Girts	Oregon pine
29	6	2x10	16	Legs	Oregon pine
29	16	2x12	16	Doublers	Oregon pine
32	24	1½x 6	16	Braces for derrick and ladder strip	Oregon pine

The Development of the Steel Drilling Rig[1]

To make the discussion clear, a distinction should be drawn between drilling machines and drilling rigs. The former is a general designation given to well-known types of drilling equipment mounted on wheels and easily portable by their own or other power from place to place without disassemblement. A drilling rig is a structure with its mechanism adapted to boring holes of great depth and removable from place to place only by disassemblement of its parts. An outfit includes, in addition to the derrick, machinery supports, wheels, etc., the boiler, engine, tools, rope, casing, and whatever materials are necessary for the complete operation of sinking holes. The steel drilling rig discussed in this paper is the structure and the essential operating mechanism, together with the house covering, etc., but does not include the drilling tools, etc.

There are three distinct types of rigs in use in the United States. The standard rig was first developed in the sinking of salt wells in the Appalachian district, and subsequently improved upon in its application to the drilling of wells for oil and gas. Its prime mover is a band wheel; two pulleys are used on the crown block, and the hoisting is done by a single bull wheel.

What is often designated in the Pacific Coast oil fields a "standand rig" is called a "California rig" in this paper. It is essentially a standard or Pennsylvania rig with the addition of a calf wheel for hoisting and lowering casing and additional pulleys on the crown block.

The rotary rig as used in the Gulf Coastal plain consists substantially of a derrick with a set of draw works and with a rotary for its drilling mechanism in place of cable tools. Rotary derricks usually have five-pulley crown blocks. The ordinary practice in Texas is to drill the well with the rotary and after completion to install the main operating parts of a standard rig to be used in the subsequent operations of cleaning, pulling tubing, deepening the well, etc. A completed well drilled with a rotary, when equipped for maintenance is fitted up substantially in the same manner as a well drilled with a standard rig.

Combination rigs are designed to facilitate the speedy interchange of cable tools or rotary in the actual process of drilling.

[1]By R. B. Woodworth, Trans A. I. M. E.

When the combination is made of a rotary rig and a standard rig, that combination is ordinarily designated a standard combination rig. When, owing to drilling conditions, it becomes necessary to utilize a calf wheel, or, in other words, to design a structure which permits the interchange of cable tools and rotary and at the same time utilizes the calf wheel for casing operations, such a rig is denominated a "California combination rig." It is obvious that this type of rig possesses more flexibility than any of the other four, and it becomes, therefore, the most complete and perfected class of drilling equipment.

With these distinctions and nomenclature in mind, we are prepared to take up the development and the gradual perfection of the drilling structure. The history naturally falls into four general subdivisions:

1. Introduction and perfection of the steel derrick.
2. The first endeavors to construct a complete rig.
3. The completed steel rig in its earlier form.
4. The extension of the completed rig to diversified service.

1. Introduction and perfection of the steel derrick.—The earliest appearance of the structural steel derrick known to me is in a catalog published by the Oil Well Supply Company in 1892. This was 72 feet high, made with steel angle-legs, steel base and crown block, and with diagonal members made of round rods and adjustable by the use of turnbuckles. There were nine panels. One of these derricks was shipped to Australia to be used in a district where wood decayed rapidly, and another was shipped in 1894 to Teheran, Persia. They also appeared in the Oil Well Supply Company's catalog, issue of 1900, and in a catalog issued in 1897 by the National Tube Works in French and English and intended for circulation abroad.

It is probable that few besides these two were constructed, but in 1903 a new endeavor to introduce structural steel derricks was made. In that year the Pittsburgh plant of the American Bridge Company built derricks for the Oil Well Supply Company in heights of 50, 60 and 70 feet, tower fashion, with three, four and five panels—that is to say panel heights on an average were 17, 15 and 14 feet. The same year the Chester B. Albree Iron Works built two or three structural steel derricks of the same general design on the order of the National Supply Company for shipment

to Vera Cruz, Mexico. These derricks were 70 feet 8 inches high, with an average panel height of 14 feet. In that same year the Carnegie Steel Company built 12 derricks for the South Penn Oil Company and the Carnegie Natural Gas Company. These derricks were 80 feet in height, 20 feet base, and were complete in seven panels averaging a little less than 12 feet in height. The derrick and base weighed 24,000 pounds. 5

These three lots of derricks were built by men experienced in structural steel work but without intimate acquaintance with oil field practice. While, therefore, they proved to be satisfactory and were moved and re-erected in the drilling of more than one well each, they were not adapted for economical service; neither did they conform to the type of construction with which rig builders were familiar.

Their performance was sufficiently satisfactory, however, to indicate that a satisfactory derrick might be constructed at a reasonable cost, and the designers of the Carnegie Steel Company continued to work on the problem in co-operation with the officials of the Oil Well Supply Company. A revised design was introduced in 1904. Previous designs had utilized supporting buttresses outside of the leg-sections to take care of what the structural steel men considered to be unbalanced stresses; in this design these buttresses were eliminated and the size of the members was reduced so as to make a lighter structure.

The present type of structural steel derrick was designed in 1908. The legs, girts and braces are made of steel angles. The splices were originally made of steel plates. The splices of the most modern type of derrick intended for use in comparatively easy drilling are made of square-root angles. The essential differences between present practice in manufacture and the practice in 1908 consists in the treatment of the joints rather than in the sizes of the main members. The number of bolts at a joint has been reduced to 8 and the total number per panel to 32. The difference is due to the fact that the dependence for the transmission of stress from one leg-section to another is placed on perfection of workmanship and not on the transfer of loads through the bolts. These are intended to be of ample strength for the wind stresses and of sufficient number to hold the joint in line and to prevent its movement under any probable upward tension caused by un-

equally distributed loads on the crown block, but not to develop the full strength of the leg-sections.

The square-root angles, however, are only made in sizes large enough to spice 4 or 5-inch leg-sections. On the larger sized derricks, such as those used with the 106-foot steel drilling rig, it is necessary to use plates. The leg-sections are not faced, but the holes in the upper section are spaced on a slightly larger spacing than the holes in the splice, and in conseuqence when erected, the two sections butt smoothly and tightly together.

Another type of derrick joint, however, has come into extensive use and is suitable for the lighter forms of structures. The ends of the leg-sections are slotted. There are slots also in the top of the splices and in the derrick-girts and braces. The bolts are put through these slots but remain permanently in position except that the nuts have to be unscrewed part way when the derrick is disassembled for removal. This is known as the "Yorke joint," after its inventor, Patrick Yorke of Washington, Pennsylvania.

A new splice has been recently devised by Philip Foukes, foreman of the Upper Union Mills fitting shop of the Carnegie Steel Company. This is intended for light drilling service and consists of a steel plate bent around the leg-section. The girts and braces are attached to the splices through lugs. The lugs and bent plates are united by three bolts. When these are tightened they clamp firmly all of the various parts at the intersection, the leg-sections, lugs, girts and braces, while the spring of the plates prevents the dislocation of nuts. There are three bolts at a joint instead of the eight used in the Yorke and Woodworth types of derricks of equivalent theoretical strength.

There are many pipe-derricks in use in Eastern oil and gas fields, made in a variety of ways. Typical of these are the derricks made by Lee C. Moore & Company, in accordance with patents issued to T. A. Neill, field superintendent of the South Penn Oil Company. The joint-clamp is made of a steel plate drop-forged to shape with lug for the attachment of girts and braces by means of bolts. Nine bolts are used in the standard drilling derrick at each joint. Second-hand pipe may be used in the manufacture of these derricks. There are many of them in use, particularly as pumping derricks over producing wells.

2. First endeavors to construct a complete rig.—The derrick

shown in the Oil Well Supply Company's 1892 catalog was intended to be used with sectional wheels, steel walking-beam, steel sampson post, steel foundation, etc., so as to form a drilling rig at least in its essential features, and a set of wheels constructed for rigs of this character was exhibited at the World's Fair in Chicago, 1893. The design, however, did not contemplate the construction of engine and belt houses, derrick roof or other similar features intended for the protection and convenience of the workmen.

In the steel drilling rig designed by the Carnegie Steel Company in 1904, provision was made for steel derrick, crown block, ladder and base, steel bull wheel and calf wheel posts, steel foundation, machinery supports and steel walking-beam. Bull and band wheels and calf wheel were made of wood. The derrick was 72 feet high and the parts of the rig weighed 34,000 pounds. Designs for steel wheels had already been made, but those used with these rigs were of wood.

3. Completed steel rig in its earlier form.—The first complete steel rigs were designed and constructed in 1908 for the Carnegie Natural Gas Company for use in Washington and Westmoreland Counties, Pennsylvania, and Wetzel County, West Virginia. The working parts of these rigs were built entirely of structural steel with the exception of the crown pulley and sand reel, which had been made already in metal. The house framing, however, was continued out only so far as the sand reel, the remainder of the belt house and engine house being made of wood. This latter defect was remedied in the three 80-foot Woodworth drilling rigs built for the same company in 1909 and first erected at Avon, Ohio, and Lumberport, West Virginia. By the end of 1910 one of the 80-foot rigs made in 1908 had drilled five wells with a total depth of 13,901 feet, and up to the end of 1912 one of the 1909 rigs first erected at Avon, Ohio, had drilled six wells with a total depth of 17,808 feet, one of which was 4440 feet deep.

4. Extension of the completed rig to diversified service.—There are three main classes of services for which bore-holes are drilled—mineral exploration work, sinking of water wells, and the sinking of wells for oil and gas. The steel derrick since its introduction has found use in each one of these fields. It has also been used with each of the recognized methods of drilling.

The 80-foot standard rigs were followed by the manufacture of

72-foot standard rigs. A few of these latter rigs have been used in western Pennsylvania and West Virginia. Their greatest use has been in Wyoming and Oklahoma. They were constructed with the same size angle-legs as the 80-foot derricks, on the assumption that while the tools were shorter and the derrick could be called upon to handle only two joints of casing at a time, the total load on the structure would not be essentially different.

The first 80-foot California drilling rig built in accordance with the 1908 design was made in 1911 and shipped to Cardenas, Cuba. This same year many of the 72-foot California rigs went to Casper, Wyoming, and were used in the development of the Salt Creek field. The 72-foot and 80-foot California rigs made up to that date were designed to carry the same theoretical working stresses as the 72-foot and 80-foot standard rigs which had been found to be of sufficient strength for all reasonable requirements in the Appalachian oil fields. It was recognized, however, that most modern California drilling required heavier structures, and designs were therefore made for derricks, machinery supports and operating mechanism which would be capable of drilling 5000 or 6000-foot wells under the severest conditions. The first 80-foot heavy California derricks were manufactured in 1913, and it is singular to note that these were not used for oil or water well drilling, but were employed by the Duquesne Light Company at Neville Island, Pittsburgh, in the support of light cables and other wires across the Ohio River during the reconstruction of a railroad bridge.

The pure rotray rig as used in the Gulf Coastal plain is nothing more than a derrick equipped with a five-pulley crown block and provided with draw works posts, with hoisting drums, and with a rotary for drilling. When the well is completed and put to pumping, the rig is extended to include the parts used in standard cable tool practice. Steel rotary derricks were first offered for sale in July, 1911. The first was 64 feet high and was sold to the Hughes Specialty Well Drilling Company at Charleston, South Carolina. It has been used in the drilling of water wells in Georgia, Alabama, South Carolina and Florida. The 86-foot rotary derrick came in due season, and also the 106-foot heavy Woodworth rotary derrick, the first of which was made in 1913 for the Oil Well Supply Company and shipped to the American Trading Company at Buenos Aires, Argentine Republic. The 86-foot rotary derrick will handle

three lengths of pipe, and the 106-foot four lengths with ample clearance for the heaviest sheaves and casing hooks.

The first two standard combination rigs were built in 1912. The first 80-foot California combination rigs were built the same year for the Penn-Mex Fuel Company at Tampico. The first 80-foot heavy California combination rigs were made in 1913 for the Caribbean Petroleum Company and shipped to Maracaibo, Venezuela. These rigs were constructed for the use of a single engine located back of the band wheel as in a California rig, and the line shaft of the draw works was driven by sprocket drive from an auxiliary sprocket placed on the band wheel shaft between the band wheel and the inner jack post. This construction places the draw works on the walking-beam side of the rig or in the identical position occupied by the calf wheel in a California rig. Interchange of tools may be effected without change in the structure, but in the California combination rigs made after this design, change from cable tools to rotary or vice versa may be effected only by the removal of the draw work posts and their replacement by the calf wheel posts or vice versa. The 106-foot heavy Woodworth-California combination rig erected at the Panama-Pacific International Exposition is constructed so as to be driven by two engines, one to drive the rotary and the other to drive the cable tools. This method of construction permits the greatest possible degree of interchangeability, inasmuch as both the rotary hoisting drum and calf wheel have their own independent supports which need not be disturbed when change of tools is made.

The first combination structural and pipe drilling rigs were made in 1909 for use of the South Penn Oil Company in the Shinnston, West Virginia, oil field. Numbers of these steel rigs, more or less complete, for use with pipe derricks have been built since that date, chiefly in conjunction with Lee C. Moore & Company, manufacturers of the Neill patent pipe derrick.

Structural steel drilling rigs adapted to the Canadian method of drilling have been manufactured by the Deep Well Tool Boring Company, St. Albans, England, and by the Oil Well Engineering Company, Manchester, England. Steel drilling rigs adapted to the Galician method of drilling are also advertised by the Galician-Carpathian Petroleum Company. I have no specific information, however, as to how extensive their use has been or

what part of the complete equipment is furnished by those companies.

Conditions which influence structural design.—The problem which confronted the designer when he began to consider the substitution of steel for wood in the construction of drilling equipment was not a simple one, in spite of the fact that in popular conception all derricks look alike, and further that men accustomed to operation in a limited field naturally imagined that when their particular problems were solved, the solution was applicable to all other problems elsewhere. It should be borne in mind, however, that in addition to the methods of drilling and hoisting which are the most immediate considerations in the design of drilling equipment, there are variations in other features, due to the arrangement of engines, to the size and depth of wells, to the character of the strata penetrated, to the preservation and maintenance of wells after completion, to the means taken for the convenience and protection of workmen and to the removal and re-use of the equipment after it has served its purpose at any one particular well, added to which there are other personal preferences of individual operators, which may cause fundamental divergences even in districts where all the other conditions are essentially similar.

As has already been noted, the heights of drilling derricks are determined by the length of tools and hoisting tackle in cable drilling practice, and by the number of joints of casing or drill pipe hoisted in rotary drilling practice. It is the latter feature which accounts for the extremely high derricks which have come into experimental use.

The strength of a derrick or drilling rig should bear a definite relation to the service which it has to perform. Considerations of transportation and erection, as well as economy in first cost, require that it be built as light as possible for the service. So far as the derrick itself is concerned, there is little waste of wood in the usual method of construction. All the steel designer has to do, therefore, is to substitute sections of equivalent strength which in turn are approximately of the same weight. There is, however, a great deal of waste in the wooden sampson posts, jack posts, longitudinal and transverse sills, engine blocks and other heavy portions of the structure. Here the substitution of materials of equivalent strength eliminates the excess weight, which is practically unavoidable in wooden construction, and as a consequence a complete

steel drilling rig of equivalent strength is some 25 to 30 per cent lighter than a wooden rig of the same strength. A standard 80-foot Woodworth drilling rig with derrick, foundations, bull and band wheels, house framing, corrugated sheeting, etc., weighs 45,300 pounds, as compared with approximately 60,000 pounds for the same structure constructed of wood.

What loads the derrick should be figured to sustain is a matter not reducible to exact formula. Drilling loads are usually not severe. It is the hoisting service which brings the greatest stresses on the structure, and this latter depends on the friction between the casing and the material with which it is surrounded, the straightness of the hole from which it is to be drawn, and the eccentricity of the pull on the crown block. The friction depends again on the size of the casing, its length, the pitch of the strata through which it passes, and the angle of repose of the materials therein. These are matters beyond practical ken. When the designer has computed the strength in accordance with the best information at hand, he has to add a percentage for unascertainable contingencies and in addition has had to remember that the driller is a very human personage and when the casing is "frozen," will load his engine to the limit for its extraction.

In the endeavor to design an 80-foot heavy derrick for use in California oil fields, I compiled various records as to depths of wells, sizes and weights of casing used therein, etc. In the process of compiling I was advised by practical oil men that the problem was to design a derrick of sufficient strength to pull 12-inch 40-pound casing in two. That was some years ago, and I have not yet been able to ascertain exactly the amount of pull required to do this. I have, however, built a number of heavy derricks which have been entirely satisfactory for field service.

It is desirable to adjust the sizes and weights of derrick members to the exact load requirements, but as far as the bracing system is concerned it is impracticable to do this. Certain sizes of angles or rods are made necessary by economic considerations of shop manufacture, and it is, therefore, practically impossible to use sections of the smaller sizes and weights which are the exact structural equivalents of the working stresses. Consequently, the designer uses the smallest size angles (or pipe in the case of pipe derricks) which the canons of fabrication show to be expedient. When

he has done this, however, his bracing system will be ample for all stresses in the derrick regardless of the load on the legs.

It is again essential for economy in manufacture that the external dimensions of the leg-sections remain constant so that the same set of shop detail drawings will suffice for derricks of different capacities. This adjustment of leg-sections to theoretical working loads is made in the wooden derricks by the nailing of additional planks to the normal leg-sections. It is done in just as practical a way in the manufacture of structural steel and pipe derricks. In the structural steel derrick the desired end is accomplished by increase in the thickness of the leg angles. The 80-foot standard derrick in the regular grade has its leg-sections made of 4 by 4 by 5/16-inch angles and the theoretical working load with a factor of safety of four is 92,000 pounds. Heavier grades are made with angles ⅜ and 7/16-inch thick and with working loads of 110,000 and 127,000 pounds with a still further increase in strength, if desired. The 80-foot regular California derrick is made heavier than the standard derrick. Its angles are ⅜-inch thick and the super-heavy grades are ½-inch thick, with a safe working load of 144,000 pounds.

The heavy derricks, whether 80, 86 or 106 feet high, are made with 6 by 6 by ⅜-inch angle legs with a theoretical working load of 223,000 pounds. The extra heavy and super-heavy grades are made with angles 7/16 and ½-inch thick and with working loads of 259,000 and 294,000 pounds. The thicknesses given are the thicknesses of the leg angles in the top section. It is usual to increase the thickness from the top downward in order to take care of the increase in stresses due to wind and working loads, particularly in the bottom panel, which is of greater height than the others.

In the case of pipe derricks the same adjustment of stresses is made by the increase in the thickness of the pipe itself and also for heavy service by inserting smaller sizes of pipe within the pipe section itself. Derricks constructed in this manner are called "duplex" or "triplex," depending on whether there are two or three pipes in each length of leg section.

Corresponding adjustments are made throughout the entire rig. It is recognized that the loads on a heavy drilling rig require heavier equipment in the operating mechanism. It has been found that a 10-foot band wheel with 4½ or 5-inch shaft is sufficient for

use with the regular grades of derricks. An 11-foot wheel with a 6-inch shaft is the standard size for use with the heavy rigs. These different sizes carry with them a corresponding increase in the strength of the crown block, jack posts, foundation sills, etc.

The 106-foot heavy Woodworth California combination drilling rig.—We have now come to a technical description of the 106-foot drilling rig exhibited at the Panama-Pacific International Exposition. The lines along which this rig has been designed have been those already stated, not to deviate from recognized standards of construction in wood and to utilize such materials in the way of rig irons, bearings, etc., as can be gotten from oil well supply stores. At the same time, one or two innovations have been introduced which are worthy of mention. The system of bracing bull wheel and calf wheel posts customary in wooden and steel rigs alike has been applied to the draw works posts as well, so that these posts, in addition to their own strength, are aided and assisted by solid braces. The walking-beam, in addition to being counter-balanced, is provided with revolving center irons, so as to permit it to be swung to one side readily when the rotary is in use. The walking-beam is likewise equipped with a spring-box at the pitman end so as to give perfect resilience to the beam whether used with manila drilling cable or with wire rope. This spring-box is a recent invention and has come into use not only with the steel walking-beam, but also with the wooden beams when used with wire line.

As a means of comparison, there is given below a table showing the detailed specifications and approximate weights in pounds of this rig. This table includes all the materials usually furnished by the manufacturers and covered by the designation "drilling-rig," as already explained. This table does not include, of course, the weight of the wood used for derrick-floor and for nailing-strips; otherwise, it is complete.

	Approximate weight in pounds
Derrick, ladder and heavy crown-block	28,960
Seven crown, sand-line, and casing-pulleys	1,430
9-inch brake-band, lever and staples	300
Bull-wheel posts, braces, and bearings	940
Calf-wheel posts, braces, and bearings	960
Draw-work posts, braces, and bearings	1,710
Foundation	7,350
Machinery supports, braces, and bearings	8,830

	Approximate weight in pounds
House framing	5,720
Walking beam and bearings	2,500
Pitman spring-box	70
Revolving centre-irons and stirrup	820
8-foot bull-wheel, long shaft	3,670
11-foot band-wheel	3,210
6-inch superior band-wheel shaft, crank, wrist-pin and keys	1,400
42-inch California double-drum sand-reel	2,000
4½-foot calf-wheel, sprocket-rim	2,210
7-inch brake-band, lever and staple	300
42-inch sprocket, clutch, keys, etc	700
55-foot sprocket chain	500
323 pieces galvanized, corrugated iron	4,930
2 engine blocks	2,800
Total, complete rig	81,310

Erection of this rig was performed by unskilled workmen. Cost of labor, including carpenter work in laying the floor, building platforms, etc., amounted to $258.00. Under ordinary conditions a rig should be erected complete by experienced rig-builders at a cost not to exceed $200, and be taken down and re-erected for $250.00. The rig is, as far as possible, fireproof; nothing can wear out except the wooden cants, which are easily renewable. Ordinary repairs, on removal, should consist merely of the renewal of the cants and replacement of bolts damaged in handling.

Methods of Guying Derrick[1]

On January 17, 1916, and again on the 27th of the same month, the Sunset-Midway, McKittrick, and Coalinga oil fields were visited by severe wind storms from the southwest. Of a total of 2000 in the Sunset-Midway field, 940 rigs or 47 per cent were blown down, and many others badly strained. I had occasion to inspect the wrecked derricks of a company that had lost 38 out of 150 or 25.3 per cent of its derricks.

Let us consider the cost of replacing the derrick and the loss of production occasioned by shutting down the wells. It is quite common and was also good practice to replace the 106-foot derricks used for the original drilling of the wells with an 82-foot derrick. These were strong, double-braced and suitable for redrilling or deepening jobs using cable tools. All usable material such as

[1]F. B. Tough in Western Engineering.

footings, sills, flooring, etc., was, of course, used in reconstruction, but the derricks proper were splintered so as to be practically useless. It cost the company already mentioned $690 for each 82-foot derrick, or about $26,220 in all. This figure does not include cases where the derrick was not destroyed but the derrick legs were sprung or the rig-housing damaged. The former charge could be properly added to the $26,220 mentioned above, since it is directly dependent upon proper guying, but the work of repairing derrick legs was charged to general repairs to derricks, and would now be difficult to segregate. While many of the derricks blown down in the Sunset-Midway field were above flowing wells which did not cease producing as the pumping wells did, nevertheless when the derrick falls there is grave risk to a flowing well because of the possible breaking of fittings, causing the well to flow without control for a time and then "sand up."

Let us assume a production of 30 barrels per day of twenty-four hours for pumping wells, with oil at $0.30 per barrel (a conservative figure), and that it was thirty days before all the wells were producing again, with an average of fifteen day's loss of production; also, that all 38 wells were pumping. The latter assumption is fair enough, since one flowing well "sanded up" will occasion a loss in production equal to several times 30 barrels per day, the assumed average production. We therefore have the following:

38x15x30 equals 17,100 barrels, total loss of production.

17,100x$0.30 equals $5,130, value of lost production.

$26,220 equals cost of reconstruction of derricks.

$31,350 equals total loss which might have been saved by adequate guying.

No allowance is made for a saving in production cost, since a company cannot reduce its operating cost materially in such a case

Dividing $31,350 by 150, the total number of rigs exposed to the storm, gives $209.00 per rig. In other words, an extra expense of $209.00 per rig for adequate guying would have been justified for these storms alone.

The method of guying now used by this company as described below and illustrated in Fig. 46 is costing $58.00 per rig, including all labor and material. If this method of guying is as efficient as it is believed to be, and would have prevented the derrick failures

in these storms, the company would have saved \$31,350.00—(150x \$58.00)=\$22,650.00. Moreover, this method of guying will outlast the life of the well and continue to do its work indefinitely.

A number of derricks were badly strained, yet did not fall. Most of these failed a little more than the half-way between the derrick-floor and the point where the lower guy was attached to the derrick leg. It was noticed that the portion of the derrick betweeu the floor and the first guywires was roughly twice as great as that from the lower guy-wires to the crown-block. This feature is more serious since this lower portion of the derrick presents the greater surface to the wind. Several derricks were seen where the guy-wires held until this lower part of the derrick bent and broke.

The failures studied were all of rigs built and operated by the same company and guyed with two wires to the leg. Wooden dead-men were used, set end to end in the same trench, which was dug approximately 3 feet deep and 100 feet from the derrick. The soil is sandy, and during most of the year dry. The guy-wires were all 3/8 inches in diameter, either seven-wire hard-laid, or six-strand, seven wires on a hemp core. The dead-men were set to pull against planks, usually 2 by 8 inches, leaning a few degrees from the vertical away from the rig, and making an acute angle with the guy-wire so that it might be pulled tight by driving the dead-man down along the face of the planks into the bottom of the trench, where it was held by the dirt piled on top of it. Of course when the wire was pulled, particularly by intermittent jerks, as during a storm, the reverse action takes place on the dead-man, tending to force the dead-men out of the ground. This tendency is increased when the stress becomes sufficient to pull the tops of the planks nearer to the derrick. Taking the co-efficient of friction between timber and timber as between 0.5 to 0.2, it would appear that there is no danger of the dead-men working up, and that the 2 by 8-inch boards would "kick out" at the bottom rather than pull over at the top, on account of the position of the dead-man. Some cases were reported where this had taken place, forcing the dead-man to pull through the solid ground in the line of the guy-wire, but all the cases investigated by me, wherever the evidence was conclusive, showed the planks tipped over toward the derrick, having forced the dead-men up through the filled dirt on top of them.

The investigation of the wrecked derricks showed that the various kinds of failures may be grouped under four heads as follows:

Cause of failure	No. of failure	Total per cent
1. Dead-men were pulled out of the ground	61	67.0
2. Guy-wires broken when kinked or pulled loose by slipping in a knot	26	28.6
3. Guy-wires broken by straight pull where no kink or sharp bend could be observed	2	2.2
4. Dead-men so rotten that either the central portion pulled out, or the wire pulled through the dead-man	2	2.2
	91	100.0

Discussion of table of failures.—In the 38 rig failures observed, 94 guy-wires had failed. Of this number three cases were not determinable, so that only the 91 determinable cases are tabulated.

Cause of failure No. 1.—Dead-man pulled out. The depth below the ground surface at which the various dead-men had been buried was determined either by digging, or if the dead-man had been pulled out, by measuring the upright planks mentioned above from the surface line to the line where the plank had been protected by the dead-man. In cases where there was any doubt, several of the planks were placed side by side and an average depth computed. The average thickness of cover amounted to 22 inches for the 27 cases determined. The surprisingly small amount of cover was probably caused by a gradual "working up" of the dead-men, as much as by shallowness of cover in the first place.

Causes of failure Nos. 2 and 3.—Guy-wires broken where kinked or pulled loose by slipping in a knot. Guy-wires broken by straight pull where no sharp bend could be observed. A common cause of failure was a square knot in a guy-wire. Of course a knot or other sharp bend is far more serious in a hard-laid line such as the seven-wire, ⅜-inch line commonly used, than in a seven-wire, six-strand on hemp-core line of the same diameter that was used in several cases. For either wire, knotting is bad practice, and after the lesson of January 27, seems inexcusable. Though the soft-laid line in a few cases pulled loose where it was knotted, it usually broke under such conditions. Whichever kind of failure took place the result was the same, the derrick collapsed. A frequent method used for

tightening a guy-wire was by the use of a couple of 2 by 6-inch by 4-foot planks. These would be placed on opposite sides of the wire with two 20-D spikes driven through them near one end and about 6 inches apart, with the wire fastened between the spikes. The other end of the "tightener" was then swung by brute force and awkwardness through 180 degrees and was fastened to the guy-wire below a third spike. The guy-wire was then bent into a flat "S" around the two 20-D spikes. No one can deny that this system tightened the wire, but in so doing it left but a small portion of the original tensile strength.

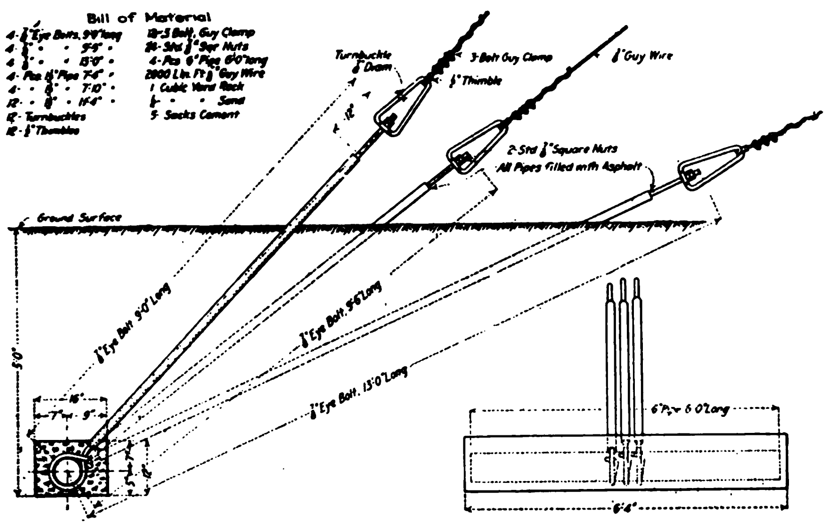


Fig. 46.
Improved Method of Guying

If it appears that an undue amount of space is here devoted to a trifling matter like a kink in a guy-wire, study the table of failures and note that of the 28 guy-wires that broke, 26 of the, or 93 per cent, broke in one kind of a short bend or another. Moreover, the two wires that broke by a straight pull and thus probably developed their full strength before failing, were in each case attached to a derrick-leg where the other guy to the same leg broke in a sharp bend, thus throwing the entire load on one wire. While there is no actual proof as to which of the wires broke first, it is reasonable to assume that it was the weakened one that failed, and that this was the indirect, if not the direct cause of the failure of the second

wire. Thus 93 per cent of the wires that broke failed because of gross mistreatment, and, in all probability, this was the indirect cause of the remaining 7 per cent of the failures.

Guy-wires have frequently become kinked in a manner that at first sight was not objectionable; for example, the guy-wires at the south-west corner of Kern Trading & Oil Co. well No. 18, Section 33, Township 32 South, Range 24 East. In this case one guy-wire was broken by a straight pull at a point a few feet above the ground. The seven wires were all "bottle-necked" at the point of failure, and there was no indication that there had been a sharp bend at this point. The other guy-wire was broken off below the ground surface. To determine the cause of the sub-surface failure, the dead-men were dug up and photographed. The sharp bend thrown in the guy-wire at the point where it pulled against a loof of the wire itself, caused the failure. On the other hand, where the wire passed first around the dead-man so as to pull against the 8 by 8-inch timber, the hitch held until the wire failed at another point, after developing, in all probability, its full tensile strength.

The foregoing illustration is applicable to attaching the wire to the derrick-leg as well as to the deadman. Even the better of the two hitches here photographed is far from desirable. The case is used here merely to illustrate a "rough and ready" practice that is decidedly unsafe.

What, now is the conclusion as to the size of the line? Is a 3/8-inch line large enough for the work? From actual observations, we are forced to conclude that the 3/8-inch guy wire, either hard or soft-laid, is strong enough if it is used properly.

Cause of Failure No. 4.—Dead-men so rotten that either the central portion pulled out with the wire, or the wire pulled through the dead-men. Though there were but two cases actually found where the rotten condition of the dead-men caused the failure of the guying system, and these dead-men had been in about five years, many of the dead-men that pulled out had rotted from 1/2 to 1 inch deep and were unsound.

Reconstruction methods.—It remains, now, to describe the improvements made in methods of guying. A few companies have merely increased the number of guy-wires with the same system of wooden dead-men set in the same way, and with no provision for tightening the guy, other than some form of "guy tightener"

mentioned above, or re-setting the dead-men. Also, in some cases, the number of square knots seems to have increased in direct proportion to the increase in the number of wires. On the other hand, many companies have improved their construction methods greatly by the use of various ingenious devices with the following general features:

1. Substantial dead-men that will neither pull out nor decay during the life of the well.

2. A rod connecting the dead-man to the guy-wire so that the latter will not be exposed to rust under the ground surface.

3. Some method for tightening the guy-wires that will not kink them, so that guy-wires may be kept taut at all times. A slack guy-wire that will allow a derrick to sway is almost as bad as no wires at all.

4. Absence of square knots or sharp bends anywhere in the wire.

5. Three guy-wires to each derrick-leg.

No one of the various systems can be properly termed the best, since such devices are usually built largely, if not entirely, out of scrap from other operations, such as old drill pipe or casing for the dead-men, and worn-out sucker rods to connect the dead-men with the guy-wires. Also the shop facilities are different for different companies. Therefore, what might be the cheapest system for one company might not be the cheapest for another.

A system of guying used with success by the Kern Trading & Oil Company is shown in Figure 46. The dead-men are set 100 feet from the rig wherever possible, depending upon the slope of the ground and other conditions. The pieces of 1½-inch pipe, through which the eye-bolts pass to the surface, are used to prevent rusting of the eye-bolts. They are filled with asphaltum after the rig is guyed. The only machine work necessary is threading the ⅞-inch rods and boring the hole in the bottom of the stirrup.

In attaching the guy-wire to the derrick-leg, the same care should be used to eliminate sharp bends and kinks as at the dead-man. Also inspection is likely to be less efficient when the derrick has to be climbed than otherwise. Since even a three-bolt clamp may work loose due to vibration, it is unsafe to rely on such a clamp entirely. A good method is to pass the wire at least three times around the derrick-leg and to place a three-bolt clamp so it will be about three feet from the derrick-leg when the guy is taut.

The free end of the wire should then be fastened below the clamp by a lineman's "makeup." This "makeup" consists of wrapping the free end to the line itself with one or more of the galvanized wires composing the line. Such a "makeup," if properly done, should carry the load even without any clamp.

No system of safety devices ever designed can be trusted without adequate inspection, and guying a derrick is no exception to this rule. Besides cautioning the men actually working on a rig to keep the guy-wires taut at all times, it is advisable to have a competent man inspect all the guy-wires on the property twice a year, in the spring and fall, and have him prepare a report showing the data when each guy-wire was inspected, and what work, if any, was done upon it at the time of inspection.

PROGRESS CHART FOR COMPARISON OF A GROUP OF DRILLING WELLS[1]

During drilling operations at certain wells of a group, it frequently happens that there are marked changes in producing conditions at neighboring wells. In order to compare the effect of drilling wells upon the other wells, a chart showing drilling progress will be found more convenient than written records. The chart here presented differs from those ordinarily used in engineering work in that it directly refers to distances from known strata rather than the ground surface. It therefore directly compares geological information with drilling and production data.

Referring to the accompanying cross-section of a group of wells (Figure 47), it will be noted that a line of correlation, "B," has been drawn across the top of the oil sands of the "second oil zone." This line defines the stratigraphy of the formations.

With the idea of presenting a graphic history of drilling operations with respect to the stratigraphy of the formations penetrated rather than the respective depths below surface, a line parallel to the line of correlation B (see cross-section) is assumed at a position below which the essential depths drilled can be plotted. The distance between the line of correlation and stratigraphic datum can be chosen arbitrarily.

[1]By R .E. Collom. Third Annual Report State of Calif. Oil and Gas Supervisor.

In certain localities where some definitely known stratum or formational marker exists—such as "Red rock," in the Coalinga east side field, or "Bottom of blue shale," in the Casmalia field—the line of correlation of this stratum in the various wells may be used as stratigraphic datum.

When such a stratum as the one referred to exists in a group of wells, one progress chart can be made for the entire group, irrespective of their location.

On the accompanying cross-section stratigraphic datum is drawn through zero depth—that is, derrick floor at well No. 6. so that all corrections for differences from surface to stratigraphic datum in each of the wells will be plus. In this position also the drilling records with respect to the principal upper water strata and other formations of importance can be plotted.

The data on the progress chart are shown with respect to time and depth. A convenient vertical scale is 100 feet to one inch. The depths drilled per day here shown would be unusual for anything but illustration. Progress in drilling is plotted from the daily tour records. It is not necessary, for plotting, to figure corrections between depths below surface and depths below stratigraphic datum. A graphic scale may merely be placed in such a position on the chart as to automatically correct for the distance of the derrick floor above or below the stratigraphic datum line.

At the left end of the progress chart is a composite graphic log of formations between stratigraphical datum and the bottom of the stratigraphically deepest well in the group.

All lines of correlation are horizontal on the progress chart. Drilling operations in any well, plotted as the work progresses, can be referred across the chart to the composite log for a check on the formational progress of the work.

As formations logged in certain wells may not be logged (although present) in a well being drilled, the combination of conditions, such as water sands, caves, shells, etc., for all wells of a group, in a composite log is a useful guide, although it should not displace the ordinary cross-section for accurate work.

In preparing cross-sections, where the correlations are definitely known, stratigraphic datum can be used as the base line, instead of sea level. As on the progress chart, this will make the lines of correlations horizontal and is a convenient method for comparison

of relative depths, thickness of formations, and other inter-related features.

The Progress Chart gives a graphic history of operations in all the wells of a group. For example, reading up the vertical line for August 1, 1917, on the attached Progressed Chart, it is easy to tell how many wells in the group are completed or in the oil sand at that date, also what wells were drilling or standing cemented.

The Progress Chart could be used to advantage in the comparison of drilling records, either as to personnel of crews or methods of drilling. A comparison under this system would be more accurate, because of more nearly equal formational conditions, than a comparison by plotting to depths below the surface.

FIRE HAZARDS ABOUT DRILLING AND PRODUCING WELLS[1]

Many fires about drilling wells have been started by having the forge inside of the derrick, also by having an open fire in the derrick in cold weather. Tools should be dressed at a reasonable distance from the rig, or better still, at some central station. However, in "wildcat" work sending tools to a central station is seldom feasible.

Gas fires about oil wells being drilled are in most instances wholly inexcusable, as permitting gas to escape unchecked from the well is a wasteful and, as a rule, unnecessary procedure. The gas should be shut in as the drilling proceeds.

Position of boilers.—Boilers should be placed so that they will not be a source of danger if a flowing well is brought in, or if flow tanks or stock tanks are overtopped. In some districts having prevailing winds, as along sea coasts, it may be feasible to place the boilers on the windward side of the well so that the greater part of the time the well gases will be blown away from and not toward the boilers. It is well to have wire gauze protectors over the tops of the boiler stacks, even at plants where oil is used for firing the boilers.

Lights for rigs.—Drilling rigs should be lighted, where possible,

[1]C. P. Bowie in U. S. Bureau of Mines Bull. No. 170.

with electric lights and not open torches. At producing wells, only electric lights should be used; neither these nor the wiring should be placed on the derrick, but rather on a pole several feet from it, and the bulbs should be protected with wire guards. If the well is flowing or producing much gas, it is better to have the lights in a cluster on a pole 50 feet or farther from the well.

Static electricity.—Static electricity generated by the band-wheel belt, or other moving parts of the machinery, has often caused fires. J. C. McCue, superintendent of the Producers Oil Company, cites an instance where he watched static electricity sparking between the band-wheel and a wet board, one end of which was buried, for two hours or more, until the board burst into flame. Mr. McCue takes the precaution to see that all machinery parts are grounded and that belts are provided with properly constructed copper brushes attached to pipe; the pipe being grounded.

An instance has been brought to the attention of the writer where a gas well in process of being drilled was ignited three times before the cause was found to be static electricity generated at the band wheel, passing through the shaft of the wheel into the sand reel and along the sand line to the bottom of the bailer, where it formed a spark in discharging from the bailer into the top of the casing as the bailer was being lowered into the top of the well.

Shooting wells and blow-outs.—Fires have been caused in shooting wells and in striking gas pockets while drilling, by rocks being blown forcibly against the sheave wheels or rig irons.

However, in the majority of blow-outs the fire, if there is one, will be caused by gas or oil coming in contact with the boiler fires. Sparks produced by rocks striking against the rig iron will not ignite the column of gas or oil unless the spark happens to be formed on the outside of the column where there is sufficient air for combustion.

Precautions about wells where compressed air is used.—In using compressed air for increasing the recovery of oil from wells, it is stated that "air-gas" used in gas engines has been ignited and the flame traveled back in the pipes to the well. This can be prevented by inserting at the proper point in the gas line a section of larger pipe filled with small iron tubes or rods that will smother the flames by cooling, much the same as the gauze in a safety lamp

prevents the gases being ignited by the flame of the lamp. Sometimes oil will flow from a well by the compressed air, and fires are reported to have been caused by oil getting into the air-gas and reaching the gas engines. This can be prevented by installing a trap in the gas line, through which the gas must pass before reaching the engine.

Gas scrubbers.—Where natural gas is taken directly from a well and used to drive engines, fires have been started by sand in the gas striking the sides of the exhaust pipe and causing sparks. This danger can be eliminated by passing the gas through a "scrubber" before it is admitted to the engine. Ordinary tubular boilers are often used as scrubbers. Valves should be placed in such gas lines at safe distances from the engines so that if the exhaust catches fire the supply can be quickly shut off.

Accumulation of gas in ravines.—Disastrous fires have been caused by gas from flowing oil wells accumulating in ravines and low places in the vicinity of the wells and there being ignited, the fire striking back to the well along the stratum of gas.

The danger of allowing gas to accumulate in this manner is exemplified in a serious accident near Drumright, Okla., in May, 1915, although the fire did not strike back to the well. It was a calm, humid evening. An automobile, with a man and two women in it, was passing near some flowing oil wells. As the car crossed the culvert over a small creek, there was a terrific explosion. The women were so badly burned that they died in a few hours. The man was also badly burned. Investigation showed that a body of gas had accumulated along the creek bed, and the headlights of the automobile had ignited this gas. The flash was seen by people several miles from the scene of the accident.

CHAPTER II.

METHODS OF SHUTTING OFF WATER

CEMENTING OIL AND GAS WELLS

The Plug System[1]

Preparation for cementing in casing.—A well properly drilled and kept full of mud is in perfect condition for cementing. Wells drilled by other methods should be lubricated or filled with mud. Before running in the casing it is best to make sure such casing will go to the bottom and turn freely in the hole. This can be done by running in say three joints of the size of casing to be used on a string of drill pipe to the bottom of the hole. It may be necessary to put a rotary shoe on the end of the casing for removing lumps or straightening crooks in the hole. When the pipe is at bottom a proper mud circulation can be established and all water (salt, alkaline or potable), as well as any oil or gas, can be completely excluded and the well brought to condition for successful cementing.

The amount of cement to be provided may be roughly estimated by assuming that one sack (95 pounds) of neat cement mixture will fill 1.25 cubic feet of space.

If, for instance, an 8-inch pipe is to be set in an 11-inch hole, it will take between 20 and 25 sacks of neat cement to fill the calculated space for 100 feet. There should be provided a mixing box about 5 feet wide and 8 feet long by 18 inches deep with gate at one end to draw off the mixed cement, two cementing plugs, bottom and top (see Figs. 48 and 49), two mortar hoes, four shovels, two galvanized iron buckets, and a barrel to dip water from; also some sort of screen to pass the dry cement through to break up and take out lumps before mixing. Six men with a box of the size named

[1]Described by Mr. I. N. Knapp. Transactions A. I. M. E. Vol. XLVIII.

and with the tools indicated will mix 10 batches of eight sacks each in one hour. It is desirable to get the mixed cement in place as quickly as possible, and one to one and a half hours is about the limit of time in which cement may be mixed for any one job of casing cementing and run in place. If more than 80 sacks of cement are required, a larger mixing box, or two boxes and more men, or a machine cement mixer, will be required.

Mixing cement mortars.—It is impracticable to specify any particular percentage of water to be used in mixing cement neat or with sand. The best guide is to use the least possible amount of water practical for the work in hand.

As hydraulic cements require water to cause them to set and they will also harden immersed in water, it is a common error to suppose they cannot be harmed by an excess of water. Experiments show that any excess in mixing is weakening in effect and retards setting and hardening. In fact, a large excess of water with prolonged mixing makes a mortar that will not properly harden at all.

If, for instance, eight sacks of cement are mixed with 18 buckets of water and the mixture works up too thin, reduce next batch to say 16 buckets. In all cases make some measure of the water to get a uniform mixture of cement going into the hole.

Methods of cementing in well casing and plugging wells.—There are several methods of doing this, such as: (1) Lowering the cement mixture in a dump bailer, particularly for plugging wells. (2) Pumping the mixture through a tubing properly arranged to force such mixture outside the casing. (3) Using two cement plugs and pouring or pumping the mixture in the casing and forcing it down and up outside the casing by pump pressure.

The first method is unreliable and uncertain even in plugging a wet hole. Its use should not be attempted to cement in casing.

The second method is open to the objection of having a string of tubing to manipulate with the casing to be set, and as ordinarily used with one cementing plug gives a wet string of tubing (pipe full of water) to pull out.

The third method of using two cementing plugs and displacing the mud with cement by gravity or pumping, as hereinafter described, is in my experience the best for general purposes, as it can be used with the certainty that the cement will be forced by

pump pressure into the space between the casing and wall of the well in the shortest possible time and with the least chance of contamination of the cement mixture.

The plugs, Figs. 48 and 49, are made of any soft wood that will drill out easily and of a diameter to pass freely through the pipe in which they are to be used.

The bottom plug should be 30 to 36 inches long, to run in 6 or

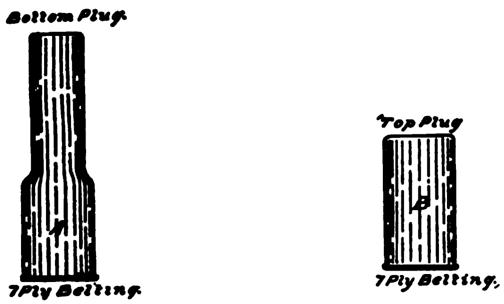


Fig. 48 Cement Plugs Fig. 49

8-inch pipe, and other sizes in proportion. The full-size portion of the plug should be 6 or 8 inches long, and the diameter then reduced to 4 or 5 inches for the rest of its length.

The top plug should be about 8 or 10 inches long for the same sized pipes. Both plugs are faced on the bottom ends with one thickness of seven-ply rubber belting so that they will fit snugly into the casing. These pieces of belting act as scavengers; the one on plug A cleans the inside of the pipe of mud as it descends so as not to adulterate the cement; the one on plug B tends to keep all the cement pushed ahead of it.

Explanation of cementing operations.—Fig. 58 indicates how the cement may be introduced into the well by gravity. It shows the lower panel of a derrick with mud pump and connections to jetting swivel, also the traveling block. The rotary is set to one side. A conductor pipe is indicated as set in the well with the top coupling replaced with a tee. The overflow from the well may thus be piped through the conductor pipe and tee to the outside of the derrick. In running the casing, as shown, into the well, the cementing plug A should be run through each joint as it is hoisted up in the derrick to be connected, in order to make sure that there

are no blisters, dents, or other obstructions in them. The casing is lowered to bottom, marked, pulled back just enough so the mud will circulate freely by pumping, and again marked.

After the mud in the well and pit is evenly tempered by circulation, the casing is hung on the slide tongs and elevators placed on the tee on the conductor pipe just under the derrick floor. The

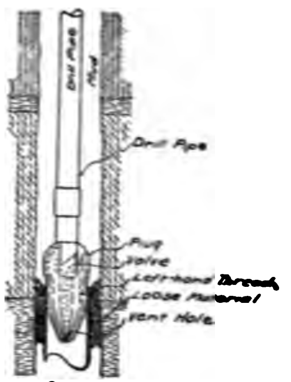


Fig. 50

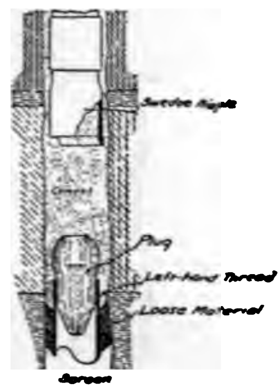


Fig. 51

Steps in operation of cementing above screen

swivel joint is unscrewed and set back. In order that the casing will take the cement by gravity the well is bailed down about 200 feet by displacing the mud with drill pipe or by bailing in the regular way.

If there is danger in bailing of a gas blowout or a cavein from water pressure other methods must be employed as hereinafter described.

The well and casing should be kept covered at all times so that nothing can fall into the hole. After bailing, the swivel joint is hooked on again and hoisted out of the way to be ready for instant use.

The casing is indicated in the figure in place ready for cementing. The mixing box is placed so that when the end gate is opened the mixed cement will flow into the top of the casing. The water barrel is placed conveniently near and means for filling it quickly must be provided. The cement required should be stacked on the derrick floor and all the necessary tools assembled.

The dry cement should be dumped from the sack onto a screen, temporarily placed over the mixing box.

It should not be attempted by this method to put in more than 80 sacks (95 pounds each), as this is about the limit that can be mixed in one hour, with seven men and the appliances mentioned. Everything being ready, the first batch (eight sacks) is mixed, the cover taken off the casing, the plug A dropped in small end up, and the cement mixture run in. It is best to pass it through a wire screen (¾-inch mesh) as it flows into the casing, so as to break up any dry lumps.

The succeeding batches are mixed and run in as rapidly as possible. The neat cement mixture being much the heavier will force the mud down and then up outside the casing. If the casing is hung up more than 12 or 18 inches from bottom, care must be taken not to push the plug A below the casing before being brought to the position as shown in Fig. 56.

The required amount of cement having been put in, the plug B is dropped in with a cement sack on it as a packer against the pump pressure, the swivel joint connected, the elevator and slide tongs removed, the casing lowered to 12 or 18 inches off bottom, and the mud pump started.

After the mud pump has run long enough to fill the swivel pipe and some pressure is shown by the pump gauge, it should be stopped and the vent cock, indicated in Fig. 61, opened to let out the imprisoned air. If air is allowed to remain in the casing, or if the suction pipe of the pump or the piston rod packing leaks, such air becomes highly compressed into bubbles in the mud and may cause trouble. Meantime the mud pit is stirred up to make the descending column of mud as heavy as possible to counterbalance the cement column outside the casing. The number of revolutions required for the pump to fill the casing should be calculated and count kept to anticipate about when the cementing plugs should meet.

The cement column is forced by the pump down the casing between the two plugs as indicated by Fig. 55. When the first plug gets to the bottom of the well it goes partly out of the casing as indicated by A, Fig. 56, and allows the cement to pass outward and up between the casing and the walls of the well. The cement floats the mud and it is pushed upward by the pump pressure.

When the plug B meets the plug A, as indicated in Fig. 56, the cement is all out of the casing and the pump stops short by reason

of the plug obstruction and the sack packer. The casing should now be given a few turns in the hole to distribute the cement. This can easily be done by two men with a chain tongs. The pump pressure remains on and the casing is set on bottom as indicated by Fig. 57.

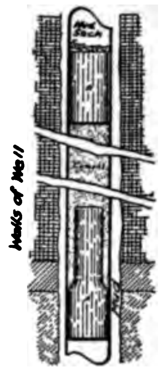


Fig. 55

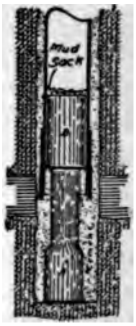


Fig. 56

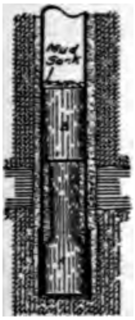


Fig. 57

Successive stages in cementing

The vent is then opened and there should be only a slight back flow, say a barrel of mud, if all air has been vented at the proper time, and the casing shoe is tight. It will be necessary to hold the pump pressure for twenty-four hours if there is a strong back flow.

Objections to cementing by gravity.—This method requires a reduction of the mud head in the well by bailing and gives opportunity for a gas blowout or for oil or ground waters to enter and cave the well.

Also, the lower end of the casing is open, which may act as a scraper against the walls of the well and the casing may become filled with thick mud enough to prevent the passage of the plugs. It is the practice of some, after a string of casing with the lower end open is run in and the mud circulation established, to hand up the casing, unscrew the swivel joint, throw in a cement sack and pump it down to make sure the casing is clear before cementing.

If there is no danger in bailing the well down, or in plugging the lower end of the casing with the thick stuff, and 80 sacks or less of cement is to be used, the gravity method is, I think, the best that can be devised.

Necessity of using neat cement.—By the means described the neat cement reaches the bottom of the casing with but little if any contamination.

The only means we have of scavenging the outside of the casing and walls of the well is by floating the mud up and displacing it with the cement mixture.

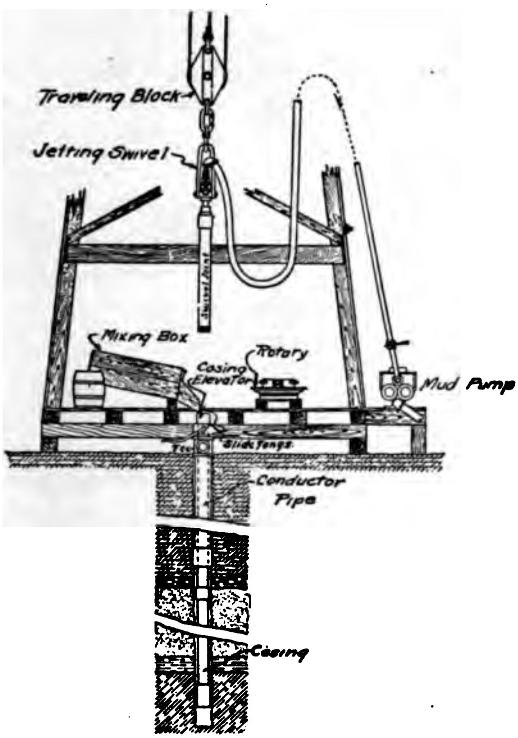


Fig. 58—Arrangement for introducing cement by gravity

The heavier the cement the better this action, hence it is desirable to use the cement neat and not reduce it with sand. The cement gets contaminated and mixed to an unknown degree with the mud clinging to the outside of the casing and the walls of the well, which also makes the use of a neat cement practically necessary.

Fig. 61 indicates a general surface arrangement for pumping the cement into the casing. The view is at right angles to that shown

in Fig. 58, with two pumps set as commonly used in rotary drilling.

To increase the cement-mixing facilities, two mixing boxes can be used as shown, or a machine mixer employed. The mixed cement is drawn into a barrel, sunk below the surface. The suction pipe of the pump to the right is extended into the cement barrel and the pump to the left has its suction opening in the mud pit (not shown).

The manipulation is the same as in the gravity method of putting in the cement, except that when the plug A has been dropped in, the swivel joint is again connected, and the cement pumped in. When the cement is all in, the vent cock is opened; air will be drawn in because the descending column of cement will push ahead the lighter mud and make a vacuum.

The swivel pipe is then disconnected, the plug B and sack put in; the pipe is again connected, and the mud pumping started. I usually arrange for the mud pump to discharge into the cement barrel so that the cementing pump will run on mud and thus clean itself and the connections of cement. Since the surface of the cement may fall 100 feet or more and the casing fill with air when opened, it is essential to vent this air, after the pump gauge shows some pressure, as before described.

Improvement on the cementing methods described.—The bottom cementing plug A has to pass partly out of the lower end of the casing in order to become operative by the common method, and this prevents the use of a back-pressure valve. As the use of such valve together with two cementing plugs was desirable in deep (2000 feet) well cementing operations, I invented a method for the simultaneous use of both, as shown in operation in Fig. 59.

This apparatus consists of a double-swedged by-pass nipple (if for an 8-inch string) made of a piece of 9-inch pipe about 24 inches long, swedged to 8 inches, threaded on both ends and couplings screwed on. Near one end of the 9-inch section two brass bars are put across at right angles, thus forming a rest for the bottom plug, and when the plug is in the position shown the cement is by-passed so the plugs can meet.

The brass bars can be made of ¾-inch brass pipe. They must be substantial, since the pump pressure may rise to 400 pounds and menting plugs out of the casing and permits the use of a back-pressure valve is screwed into the bottom coupling on the by-pass

nipple as shown in Fig. 59. This should be a substantial brass valve for deep work. The bars and valve are made of brass so that they can be easily drilled out, with the wooden plugs, at the proper time.

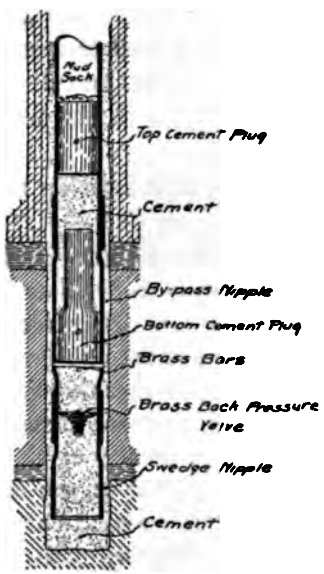


Fig. 59
Arrangement for cementing with double swedge

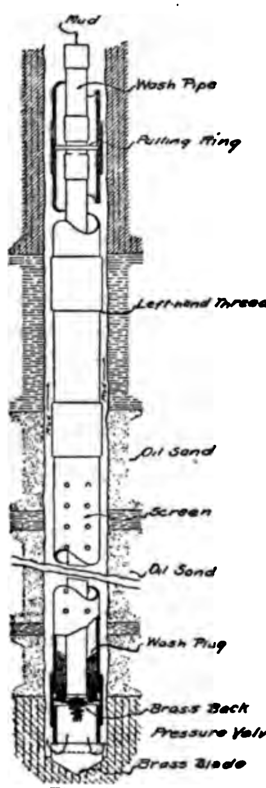


Fig. 60
Arrangemen for cementing above screen

Under the back-pressure valve is fitted a 9 to 8-inch swedge nipple not threaded on the 9-inch end. This acts as a casing shoe and protects the valve.

The two couplings on the by-pass nipple should be screwed up as tight as possible and then pinned or riveted in each thread. When the wooden plugs, brass bars, valve, and cement are being drilled out, there is a possible danger that these threads may work loose by the action of the drill and the parts unscrew. This would make trouble, and should be avoided.

Advantage of using the double-swedged nipple.—This invention

(not patented) prevents the possible accidental passage of the cementing plugs out of the casing and permits the use of a back-pressure valve. This valve prevents thick mud from being forced back into the casing. The casing can be partly floated, thus making a long string much easier to handle. The casing can be bailed down to take any quantity of cement by gravity without endangering the well, also the cement mixture after passing the valve cannot flow back into the casing. The cementing operation may be done by gravity or pumping as before described.

Setting screen and cementing casing above.—When casing cementing is required, it is usually necessary also to set a screen, to make a proper test for oil or gas or bring a well in from a known horizon. In such cases I prefer to set a screen the full size of the casing required, for the closer the screen fits to the walls of the well the better for the well.

The screen with two joints of the same size casing above may be run in on a string of drill pipe.

Fig. 60 shows a screen set in place with all necessary fittings. The brass blade shown at the very bottom is to produce friction in order that the left-hand thread at the top of the screen may be easily unscrewed at the proper time. The short one-thread nipple is to hold the brass blade and protect the back-pressure valve. This valve is for the purpose before described, and permanently closes the lower end of the screen when set. The wash plug in the lower end of the screen serves as a guide and packer to the wash pipe. The function of the wash pipe is to carry all the mud down through the screen and the back-pressure valve so it may pass up outside the screen and casing.

The screen may be of any size or length and made with drill holes only or wire wound to any mesh desired. At the top of the screen is a left-hand nipple two or three feet long with the left-hand thread up. By putting the proper tension on the drill pipe and turning the left-hand thread unscrews and leaves the screen in the hole. The wash pipe is pulled out by the pulling ring.

When the coupling (6 or 8-inch) containing the pulling ring is landed on the elevators at the surface and the joint above unscrewed, then the wash pipe elevators (2 or 2½ inches) may be put on under the top coupling of the string and the wash pipe pulled.

Plugging top of screen for cementing.—A soft wooden plug about 20 inches long is made as shown in Fig. 50. The bottom of the plug is made conical as a guide in entering and the body cylindrical to fit tight into the screen nipple, which has a left-hand thread.

The top is rounded over to guide the swedge nipple that is later placed to fit down over the left-hand thread. A 1¼-inch vent hole is bored through the axis of the plug in order to allow the mud to flow back into the drill pipe is setting the plug.

A counter-sink 6 inches deep is made in the top of the plug so that it may be fitted on the end of the (4-inch) drill pipe. A piece of leather is nailed over the vent hole in the bottom of the counter-sink so as to make a flap valve.

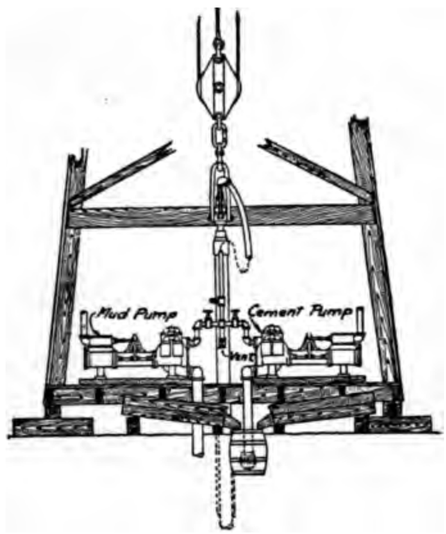


Fig. 61
Arrangement for introducing cement by pumping

The plug is then run in on a string of drill pipe to bottom.

I have found by experience that enough loose material will be pushed ahead of the plug to pack efficiently outside the left-hand nipple so that no cement will flow down outside the screen in cementing. Pump pressure is put on the drill pipe, which closes the flap valve in top of the plug. The string is then raised and the drill pipe pulls out of the plug, an immediate fall of pressure being shown by the pump gauge, indicating that the plug is left in place.

The string of pipe is pulled out and the well is then in shape for running in a string of casing and cementing.

Cementing the casing above the screen.—On this string should be a by-pass nipple, as previously described. Whether a back-pressure valve is to be used or not is determined by the depth and conditions of the well. The string (if 8-inch) should have on its bottom end a 9 by 8-inch swedged nipple. The 9-inch end should

be cut with an offset and the lip thus formed bellied out slightly as indicated in Fig. 51. The purpose of this lip is to guide the plug and screen in line by turning the casing and to give a "feeling" which will indicate whether the swedge nipple is resting on top of the plug or has slipped down over the left-hand thread as it should. The string is lowered to bottom and marked, then pulled up until the circulation of mud is good.

The cementing operation may be done by the methods already described. After the cement has had time to harden (five days should be plenty), the wooden plugs, brass bars and back-pressure valve may be drilled out, the inside of the screen washed out with mud down to the wash pipe plug, and the drill pipe then withdrawn. A gate valve should be put on the casing, and the well is then ready to bail to test for oil or gas.

Plugging wells by cementing.—The two-plug cementing system is well adapted to put in a cement plug in the bottom of a well to exclude water or fill a well any distance with cement mortar. For instance, if it is desired to plug off the bottom 20 feet of a hole, the proceeding would be practically the same as cementing in a casing but no by-pass nipple or back-pressure valve would be used, and the drill pipe would be employed to pass the cement to the bottom of the hole. The bottom plug should be made 36 inches long, but not tapered, and bored full of holes, which are filled with lead so that the plug will stay on the bottom. The operation should be so performed that the bottom plug will shut off the pump when it reaches bottom, and not by-pass the cement as before described The drill pipe should then be pulled back until the bottom plug passes out. About half the cement to be placed should be pumped through, then the drilling pipe should be pulled back proportionately.

The top plug and the sack should be used to push the cement ahead and to prevent mixture with the mud following.

In cementing off 20 feet a surplus of cement mixture should be put in and the drill pipe pulled back only about 22 feet from the bottom and the mud circulation kept on for half an hour to dissipate the surplus cement.

By this method of building up a cement plug from the bottom there need be no time limit to the completion of the cement-plugging operation, as the drill pipe can be pulled back from time

to time and cement kept going in until the hole is completely filled. The drill pipe should have a scavenger plug passed through it about every hour to keep it clear of set cement; the joints as disconnected at the top should be washed clear.

Short plugs should be made of neat cement. Larger ones may be cement and sand mixtures.

Dump-Bailer Cementing Process[1]

General remarks.—In cementing a string of casing with the dump bailer, the liquid cement is lowered to the bottom of the hole with a bailer which, as its name indicates, discharges or dumps its load instead of picking it up like the ordinary bailer. By this method two or three tons of cement is dumped into the bottom of the well. As many runs are made with the bailer as may be necessary to deposit the entire quantity of cement to be used. The required quantity can almost never be lowered in one load. After this is done, the casing is pulled up 20 to 40 feet off bottom, or so that the shoe will be above the cement level. The casing is filled with water and then closed at the top with a steel plug, or other suitable fitting, and is lowered firmly to the bottom of the hole. There being no outlet at the top of the casing for the water, the cement cannot enter at the bottom, so it takes the only open course and rises outside the casing, filling the space between the casing and the walls of the hole.

Description of dump bailer.—There are several types of dump bailers in use; also, there are several ways to transform an ordinary dart bailer into a makeshift dump bailer, but such makeshifts are unsatisfactory and likely to cause trouble. A satisfactory type of dump bailer is the one shown in Fig. 61-A. The shell of this bailer is of two joints of pipe swaged to connect in a coupling of the same external diameter as the joints. As the bailers vary in size according to the size of casing in which they are to be used, dimensions are omitted here. The bail "a" terminates in a bottle neck through which the rod "b" is free to slide. The enlargement at the lower end of this rod is bored as a rope socket to receive the ⅞-inch wire dump line "c." The rod is provided with a latch "d," in general design similar to that on the shaft of an old-fashioned umbrella. The upper end of the rod is threeaded to screw into the

[1]By F. B. Tough. U. S. Bureau of Mines Bulletin No. 163.

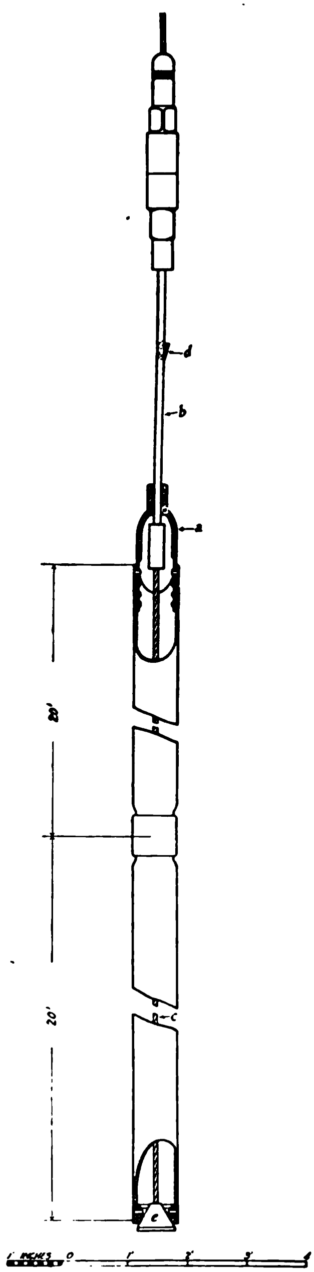


Fig. 61A—Dump Bailer

bottom of a tool joint. This joint has a pin on its top to make up with the box of the rope socket so that the dump bailer may be run on the drilling line. Riveted to the bottom of the bailer is an annular steel valve seat. The valve "e" is of steel and in the form of a truncated cone. Of course, a ball would do the work as well as the cone. The wire line, or chain if preferred, which connects the rod "b" with the cone, must be babbitted, or otherwise securely attached to both rod and cone, as the entire weight of the bailer and contents must be carried by the dump line or chain. It is worth noting that if either of these two babbitted connections fail, only the cone, or at worst the cone and the dump line, will be left in the hole, as the shell of the bailer will hang on the butt of the rod "b."

When this bailer is run to bottom, the rod slips down through the bottle neck in the bail, thus throwing about three feet of slack in the connecting cable. When the bailer is lifted again the latch engages with the bail and the entire device is brought to the surface with the valve dangling about three feet below the valve seat. There is thus no possibilty of the bailer not discharging its contents. In running such a bailer in a hole full of fluid it tends to float if lowered too rapidly. The latch will then trip the bailer and discharge the contents. Such an accident is particularly apt to occur when the fluid level is several hundred feet below the surface. Such premature unloading may take place without the driller's knowledge and go undetected until the

job is found to be unsuccessful. All this trouble will be avoided by care in lowering the bailer slowly enough, allowing no slack in the drilling cable. In the type of construction illustrated in Fig. 61-A more than two joints of the pipe may be used if so desired.

Method of use.—In order to reset the latch for another run, the shell of the bailer must be supported and the rod lowered enough to allow the latch to be pushed into the rod and so held until the rod is pulled up through the bottle neck. This can be done more conveniently with the top of the bailer near the derrick floor than by resting the bottom of the bailer on the floor. A convenient method is to have two pieces of timber 4 by 6 inches by 2 feet coped to fit the bailer, with two long bolts connecting their ends. By drawing the bolts tight the wood clamps will grip the bailer and, resting on the top coupling of the casing, hold it while the latch is set. The bolts may be loosened and the bailer lowered through the clamps, which are then in place when the bailer is again raised through them.

The dump-bailer method is frequently used when a water string is to be set with a relatively small amount of cement, say less than two tons. The cement is mixed in a box on the derrick floor in batches according to the capacity of the bailer. After cement has been wet, it should not be held over for the next batch. Surplus cement, after the bailer has been filled, should be discarded. A convenient rule is to figure that each sack of cement when mixed will occupy 1.15 cubic feet. This, of course, allows for the excess of water used to obtain the necessary fluidity, as well as to prevent the cement from taking its initial set too quickly.

The bailer latch is set and the bailer hung in the hole with the shell seated on the cone valve so that theh top of the shell comes level with the floor and under a spout or swing pipe leading from the cement box. The bailer is then loaded and run to bottom in the manner described. It is advisable to have a bailer large enough so that the period from the time the first batch of cement is wet until the job is completed will not exceed two hours. It is important to have enough men with hoes at work to insure that the mixing of each batch is commenced as soon as the last of the preceding batch has left the mixing box, and the mixed cement will not have to be kept waiting for the bailer. Frequently, while a driller and tool dresser are lowering and dumping a bailer, pulling out and re-

setting the latch and getting the bailer in position for the next charge of cement, the other men get the cement ready to pour. This is the ideal arrangement, but one dares not speed up the bailer movements to any great degree, and as more than five hoes in say, a 10-sack mix, does not accelerate mixing, the controlling time factor is the depth of the hole. Nevertheless, when cementing a deep hole care can be taken that the mixed cement does not have to wait for the bailer. If the dry cement is piled into the high end of the mixing box away from the outlet, and a nozzle be used on the water hose so that a high-pressure stream of water may be played back and forth across the box impinging on the pile of cement so as to cut and mix it in slices 2 to 4 inches thick, the cement not only mixes more quickly, but with fewer lumps, and consequently requires less hoeing than if mixed entirely with hoes.

During cementing, the hole should be kept full of water, if possible. After all the cement has been dumped, the casing is filled with water and set, as described. The well should be left undisturbed at least 24 hours before the pressure within the casing is released. After this time it is advisable to stretch the casing as much as experience has shown is allowable. The casing is then hung on clamps in this position so that it is held both at the top and at the bottom; otherwise the pipe tends to bend from its own weight.

Cementing Wells Without Plugs or Barriers[1]

The liquid cement may be, and, in fact, sometimes is, pumped into the casing on top of the liquid in the hole—mud fluid or water—and is forced down the hole either by mud-fluid or water above it. This procedure is like increasing the diameter of the tubing job till it becomes too large to go inside the casing so that the casing itself must be used instead. The wash water may be either gaged in tanks or run through a meter.

Two important questions arise in regard to this method, as follows:

1. Will there not come a time as the diameter of the tubing increased when the cement, being heavier than the mud-fluid or the

[1] F. B. Tough, in U. S. Bureau of Mines Bulletin No. 163.

water, will work down into the lighter fluid below and become so diluted that it will not set?

2. How will an operator determine the end point and know when to land his casing?

To answer the first question it is well to define limits and to consider casings between the sizes of 3 inches and 10 inches. Strings of 12½-inch casing are sometimes cemented for certain drilling advantages gained thereby, but rarely is a string of casing larger than 10 inches in diameter cemented by a pumping method. It is fair to assume that if the cement does not mingle with the other fluid in the hole under conditions favorable to intermingling, it will not do so under conditions less favorable.

Citations may be made of two wells having unfavorable conditions under which the cement set. In both these wells the peculiar conditions of the job made it impossible to foretell how much cement would be required; hence a considerable excess had to be provided to insure a sufficient supply. Both illustrations are from the wide experience of Mr. F. W. Scott of Taft, Cal., who was in personal charge of the work. One well belonged to the Pacific Midway Oil Company, near Maricopa, Cal.

The other instance involved a bottom-hole job in which it was important that the cement should fill 35 feet in the bottom of the hole, but no more. The hole was 4135 feet deep in the east side of the Coalinga field. Forty-two sacks of cement were mixed, 40 pounds of water to 100 pounds of cement, and pumped to the bottom through 2-inch tubing. When the cement was all in the tubing was pulled up 35 feet off bottom and the pumps started forcing water down the tubing until the cement above this point was all washed back to the surface between the 2-inch tubing and the 6-inch casing. Mr. Scott was kind enough to catch a sample of the return cement in a quart preserve jar and express it to the writer after the cement had set. Ten days after the sample had been caught, the writer broke the glass jar away from the cement and found it set hard. There had been no shrinkage of the cement cake away from the wall of the jar, as was demonstrated by the highly glazed surface of the cake, and by the impress of the label pressed in the glass. When the jar was first opened the top of the cement was sufficiently soft to be easily scraped with a knife, but the lower part was hard. Though this slug of cement gave the

appearance of having suffered considerable dilution when in the liquid condition, it had set hard enough for ordinary well purposes.

The whole force of these instances in connection with cementing casing without the use of plugs or barriers is that they represent conditions where the cement was far more subject to dilution than in ordinary cementing of casing without plugs. When cement is pumped down tubing and forced back to the surface between the tubing and the casing against the force of gravity with all the drag of friction against casing and tubing, the agitation is considerable. The conclusion seems justified that when cement is pumped down inside casing 10 inches in diameter or smaller, without the use of plugs or barriers, the cement mixture and the other fluids in the hole tend to intermingle, though as a rule this intermingling is not serious, particularly when the cement has originally been mixed with only a small proportion of water.

The second question as to how to determine the time to land the casing brings out a serious weakness in the method. As either a meter or a gage tank may be used, the relative accuracy of gaging or metering the wash water is not the question at issue. Considering that such gaging is usually done in 50-barrel or 100-barrel tanks that have been dumped off the trucks numerous times, and had their sides dented, to be afterwards driven out to restore more or less the original shape of the tank, the writer thinks the relative accuracy of the two systems is about the same. The meter is more easily read than the low-gage wet-line mark on a notched stick, particularly if the cementing is done at night. The use of the meter also reduces the chances of error by eliminating one set of computations. All things considered, assuming no errors in computation, the general average of 10 cubic feet of allowable variation between the volume of measured water and the actual capacity in a 2500-foot hole of 10-inch casing is a close limit. This is an allowable error of about 0.7 per cent, and is here applied alike to both methods of measurement. Ten cubic feet in 10-inch casing occupies about 18 linear feet; that is, an operator's computation should allow for leaving at least 18 feet of cement in the casing to obviate the possibility of washing the cement away from the shoe. He may find either no cement or about 36 feet of it in the casing, according to whether the allowable error has been minus or plus. Many oper-

ators do not object to this feature, and sometimes require that 10 or 20 feet of cement be left in the hole.

There are two causes for such a requirement—first, the fear that too much water will pump the cement not only to the bottom but up outside the casing and away from the shoe joint to a point where it is not needed. An excess of water will undoubtedly produce such

Fig. 62
Honolulu Cementing Head

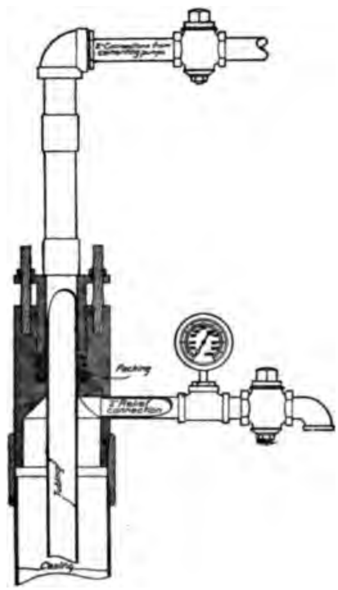


Fig. 63
Cementing head of stuffing box type

a result. The second cause is the claim that the latter part of a batch of cement is "mushy" and had better be cleaned out of the hole later than to be put behind the casing and not do its work. This contention is supported by the results at numerous wells, where the cement left inside the casing had a few feet (at some wells) of mushy, chalky deposit on top, the underlying cement being set hard. So firmly is this conviction held by some operators that even when using the two-plug method they drop a timber 4 by 4 inches by 20 feet long into the casing between the plugs, which will stop the second plug 20 feet above the first, thus leaving this amount of cement in the bottom of the casing. This practice does not refer to instances where a timber, say 10 feet long, is used to obviate the danger of both plugs escaping from the casing.

It seems probable that the "mushy" cement constitutes that which has adhered to the inside of the casing and gradually settled to bottom much diluted, or is composed of good cement left inside the casing and prevented from settling by mechanical agitation, such as the working of gas or some other cause.

On the other hand, there is a serious disadvantage to drilling hard cement out of a water string. Any pounding or grinding inside the casing has a tendency to crack and loosen the cement mass formed around the exterior of the pipe. If some form of casing method is to be used, the writer would prefer the two-plug system without the use of a timber between the plugs, unless, owing to certain peculiar conditions of the hole, such a timber should be necessary to prevent the second plug as well as the first from escaping.

Tubing Method of Cementing[1]

The tubing method of cementing casings in wells is subject to many variations and modifications. The essential features are that the liquid cement enters the well through tubing two to three inches in diameter which extends to within a few feet of the bottom, inside of the casing that is to be cemented. Some provision must be made to prevent the cement from backing up between the tubing and the casing, and to force it to go up between the casing and the wall of the hole. For this purpose a packing device of some kind is used which seals off the annular space between the tubing and the casing. The packing device may be placed at either end of the string of tubing or at any intermediate point. For mechanical convenience it is customary to put the packing device either at the bottom or the top of the tubing.

In cementing a well by the tubing method the driller should make sure that the fluid will circulate before any other work such as putting in tubing is started. If water cannot be forced from inside of the casing around the shoe and up outside of it, it is obviously useless to try to force cement through. Assuming that it has been possible to get circulation with water or mud fluid, the tubing may be inserted with the packer on the bottom. A disk packer is frequently used for such jobs, although any other kind of a packer meeting the general requirements will do. After the

[1]F. B. Tough. U. S. Bureau of Mines Bulletin No. 163.

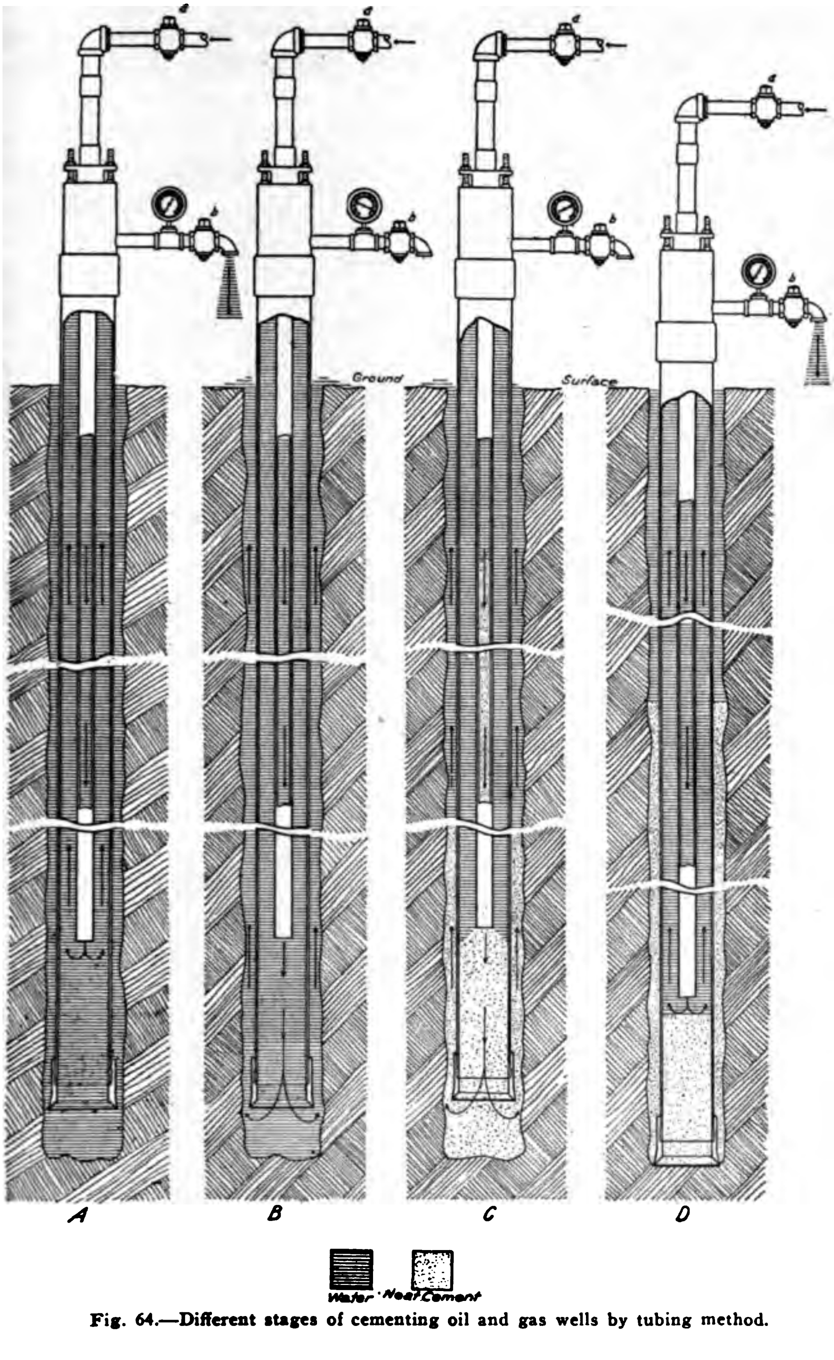


Fig. 64.—Different stages of cementing oil and gas wells by tubing method.

cement has been mixed and pumped in under the packer and followed by sufficient water to flush the tubing clear of the cement, a stopcock, or gate, at the top of the tubing is closed, and the casing is lowered to the bottom of the hole. After the casing is thus set on bottom, the tubing, together with the packer, should be

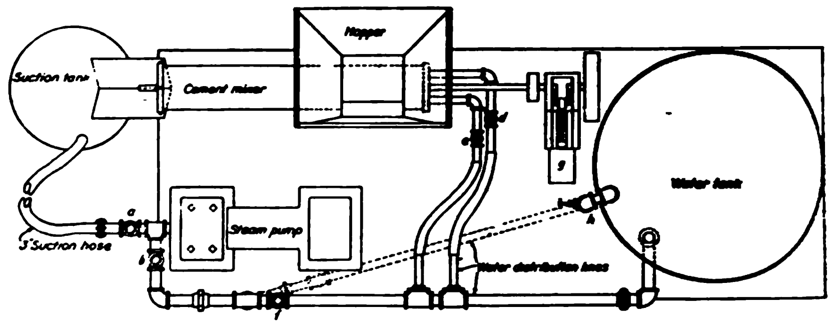


Fig. 65.—Scott Cementing Outfit Plan.

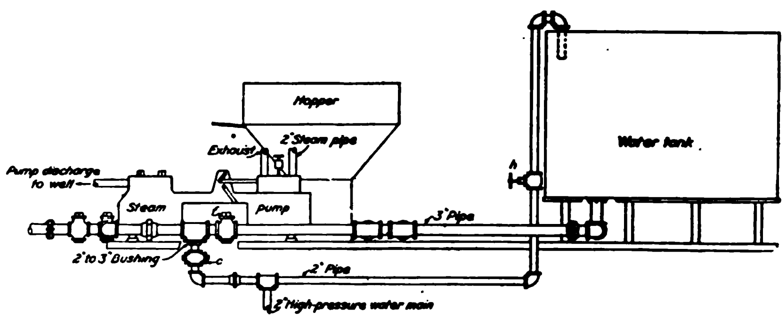
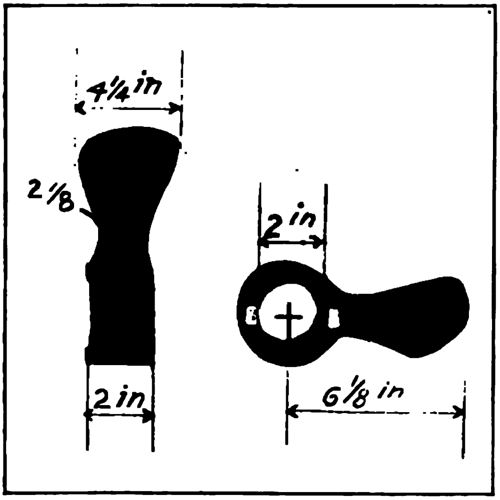


Fig. 65a—Scott Cement Outfit Section.

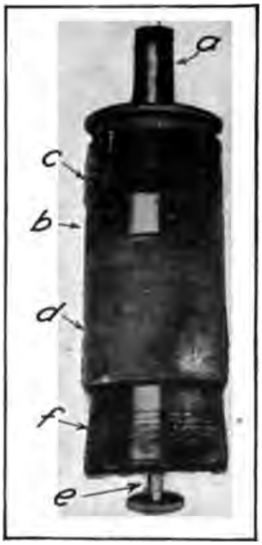
pulled up enough to free the packer before any residual cement has an opportunity to set. After the packer has been thus loosened, water is pumepd down the tubing and back to the surface between the tubing and the casing in order to wash any cement from inside the casing. The tubing is then pulled out bringing the packer with it. This done, it is advisable to completely fill the casing with water and close the top with a plug or other suitable fitting, and

A. Cementing Head, Kern Trading Oil Co.

C. Scott Tight Head



B. Mixer Blades of Scott Cementing Outfit



D. Baker Cement Container

Fig. 66—Various Appliances Used in Cementing Operations.

—Photos Courtesy of United States Bureau of Mines.

to leave the hole in this condition while the cement sets. In fact, a column of water should be kept inside of the casing after any cementing job in order to counteract the tendency of the liquid cement to run back into the casing through any stray channel under the shoe. Some operators go so far as to set a pump to hold a certain water pressure on the casing, perhaps 50 pounds per square inch or more, as may be required. The pump is watched and is so regulated as to counteract any leakage in the fittings and to maintain a steady pressure on the well.

The disadvantage of the bottom packer is that it may leak cement under high pressure and by-pass so much of it above the packer that the packer cannot be pulled. The operator will then have to drill the cement and the packer out of the bottom of the water string, with perhaps a joint or two of tubing. To avoid the possible loss of tubing there should be a left-hand thread connection between the tubing and the packer. Even though sufficient cement may have been forced outside of the casing to make a watertight job, the severe pounding of the tools while drilling up cement and junk will probably crack the outside cement and may even tear a hole in the water string itself.

This disadvantage has been overcome by omitting the packer at the bottom of the well and using one at the top instead. There are several top packing devices in use. Two forms of top packers, or tight heads, as they are commonly called, are shown in Figs. 62 and 63.

In addition to changing the positions of the packing devices, there are several variations in the method of mixing and pumping the cement into the tubing. One of the best systems in use is that operated by William F. Scott of Taft, Cal.

Construction and operation of Scott cementing outfit.—As shown in Fig. 67, the Scott outfit is mounted on a stout wagon to facilitate its transportation. It is hauled by team or motor truck to a convenient position near the well to be cemented. The main features of the outfit are the wagon, water tank, cement mixer, single-cylinder steam engine to drive the mixer, cement pump, small suction tank, and top packer or tight casing head.

The water tank is a galvanized-iron tank of convenient size, securely mounted on the rear of the wagon and fitted with a 3-inch flange in the bottom connected to the 3-inch suction line to the

pump. This line has a 2-inch intake from the main water-supply line, and also has a 2-inch branch discharging into the top of the tank. This tank is used for gaging the water pumped after the cement.

The cement mixer was built by Mr. Scott according to his own design. The mixing barrel is a piece of 12½-inch casing about 6½ feet long with a feed hopper as shown in the illustrations. This

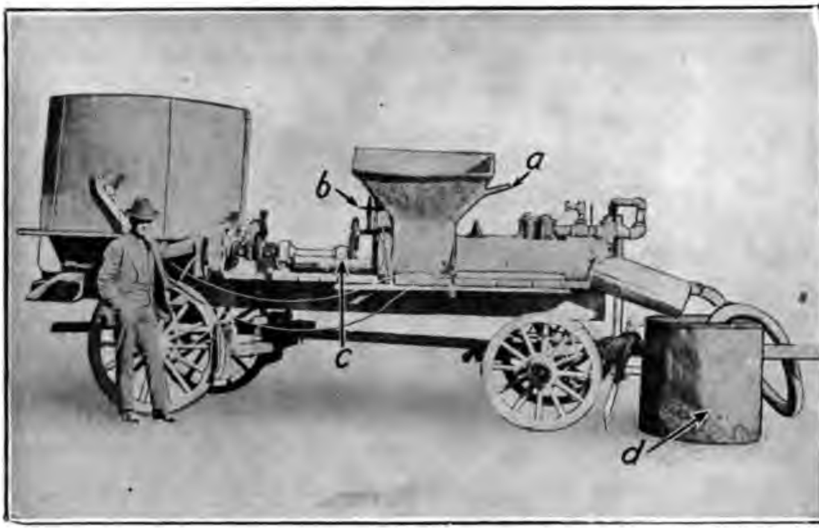


Fig. 67—Scott Cementing Outfit, viewed from side
—Photo Courtesy of United States Bureau of Mines.

hopper feeds the dry cement to the mixing barrel below. The feed is regulated by a sheet iron door operated by a lever (Fig. 67). To insure uniform feed and to break any lumps in the dry cement, thus preventing it from clogging in the hopper, there is a shaft fitted with radial iron pins. The pins are about 3 inches long, made of ¼-inch round iron. The end of this shaft and its drive sprocket are shown at b. This sprocket is chain driven from a jack shaft, which is in turn driven from a sprocket on the main line shaft of the mixer, thus causing the small feeding shaft to rotate at a greatly reduced rate of speed compared to the speed of the line shaft.

The end of the mixing barrel under the feed hopper is closed by an ordinary cap to fit 12½-inch 10-thread casing. In the cap are three holes. The central hole admits the drive shaft and acts as a bearing for it. The other holes ,one on either side of the cen-

ter, admit water in the mixing barrel. The two intakes provide a more uniform distribution of water than would be possible with only one. The line shaft is flanged directly to the engine shaft, thus gaining strength, simplicity, and compactness by a straight line drive. The bearing at the discharge end of the mixer is held by a semi-circular cap as shown in Fig. 68. This cap is held in place by three cap screws and thus can be easily removed. The cap

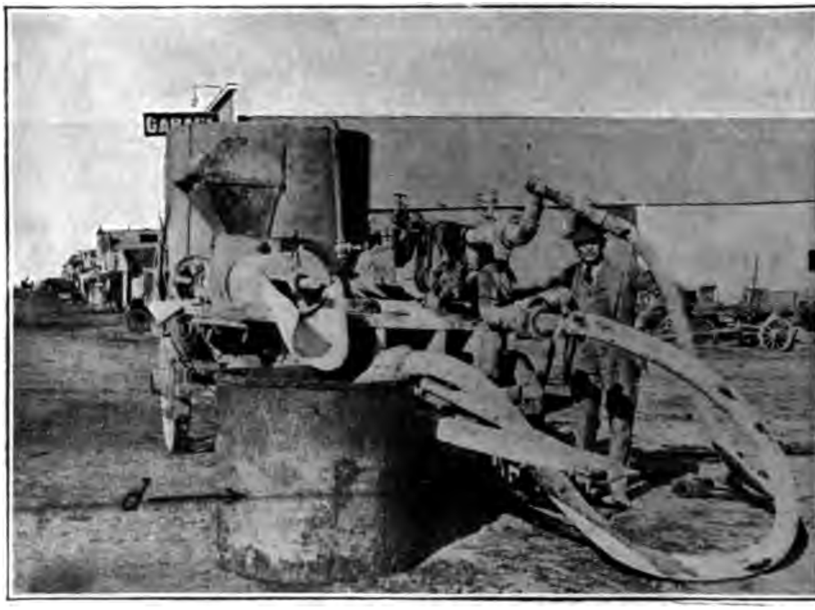


Fig. 68—Scott Outfit; view of discharge end
—Photo Courtesy of United States Bureau of Mines.

screws also permit accurate centering of the line shaft when adjustments may be necessitated from the replacing of broken mixing blades. The small three-bolt shaft coupling shown at (Fig. 67), may be disconnected and the adjacent sprocket taken off, thus leaving the line shaft free to be removed for cleaning and repairs.

The 2-inch line shaft has a set of cast-iron mixing blades (Fig. 66-B) mounted on it. These blades are cast with lugs on one side of the hub and notches with 90 degrees to them on the opposite side. When a set of blades are slipped on the shaft the notches on the one will mesh with the lugs on the adjacent hub, thus each successive blade is held at 90 degrees to the one preceding it. Such an

arrangement causes the entire set to rotate as a unit without any radial slip. Two blades at each end of the set and one or two in the middle are attached to the shaft with set screws. This construction permits the easy and quick replacement of broken blades and obviates any machine work on them except that necessitated by the set screws. The blades being of cast iron may break if a large nut, bolt, or other piece of iron gets into the mixer by accident along with the cement. It is far better to have a broken blade in the mixer than a shut down in its operation. Obviating a shutdown after the mixing of the cement has once started is most important, as the wet cement would not only have an opportunity to set in the mixer, but delay might mean failure in the entire cementing job. The mixing blades are about 6⅛ inches long from the center of the hub to the periphery. The pitch of the blades is such that when one looks into the discharge end of the mixer the shaft must rotate in a clockwise direction. This direction of rotation tends to clear the cement away from the bottom of the feed hopper.

If the main shaft of the mixer rotates at 400 revolutions per minute, a ton of cement (20 sacks) can be mixed in two and one-half to three minutes. The cement passes through the chute at the discharge end of the mixer int othe small suction tank d (Fig. 67), from which it is taken directly by the pump and forced into the well without the necessity of working it at all with hoes. The mixing is entirely mechanical, thus reducing labor and accelerating the process.

The engine used is a single-cylinder, 4½ by 5 inches Clark steam engine, and gives entire satisfaction.

A 10x4x10-inch Snow duplex pump is used to force the cement into the tubing. This pump will deliver at about 750 pounds gage pressure.

A small galvanized iron tank of about 20 cubic feet capacity is used as a suction tank. Almost any strong tank or box of 10 to 20 cubic foot capacity will do for the purpose. The tank should not, however, be of a low squatty design. The object is, of course that the suction tank carry as small a quantity of cement as possible so it will be drawn off by the pump as fast as it is mixed, allowing no time for any settling to take place in the suction box.

The top packer, or tight head, is designed in many forms.

Fig. 66-C shows the tight head used by Mr. Scott when ce-

menting a string of 8¼-inch casing. The sack wrapped around the casing is more to illustrate the necessity of packing than to recommend the method illustrated. Ordinarily when this head is used a steel plate bored to take the tubing is slipped over the last joint before it is set up. This rests under the top coupling of the tubing and presses soft hemp or other packing into the annular space between the tubing and the tight head.

Fig. 66-A, shows a tight head used successfully in the Coalinga and the Sunset fields. This head is bored to allow passage of the 3-inch tubing, but not a coupling, and must therefore be slipped onto the last joint of tubing before the latter is set up. The head is then screwed into the top coupling of the casing to be cemented. The rim of the hole through the casing head has a small bevel turned around it to receive a ring of hydraulic packing that is put around the tubing and under the coupling. The follower plate may be drawn firmly down on top of the coupling by the stud bolts if necessary.

Some operators in the Midway field have had difficulty with various types of tight heads that require packing to make a tight joint between the tubing and the casing head. The trouble was occasioned by leakage around the packing toward the finish of the cementing job, when the highest pressure is naturally used. To get around this difficulty the Honolulu casing head shown in Fig. 62 was designed and has proven satisfactory. In this head the packing is replaced by threaded connections.

In using either the Honolulu or the Southern Pacific Company head, the tubing must be lifted in order to provide a relief vent for washing surplus cement out of the tubing and casing after the tubing has been landed. With a Scott head this operation is accomplished by opening the 2-inch stopcock near the pressure gage.

The tight head of the stuffing box type (Fig. 63), made and used by the fuel department of the Southern Pacific Company consists of a stuffing box and follower drawn down by two ⅞-inch stud bolts. The tubing will work through this gland, or, if preferable, a coupling may be set on top of the follower, thus pressing the packing more firmly together ,as shown in the drawing. With this type of heading it is not necessary to set the weight of the tubing on the follower gland to compress the packing, hence the bottom of the tubing may be set at any desired depth without regard to the posi-

tion of couplings at the surface. It is believed that this form of stuffing box if thoroughly packed will prevent leakage under the most severe conditions.

Conditions under which tubing method is used.—The tubing method is applicable to cementing water strings that are not likely to "freeze" on standing while the tubing is being inserted. In general, the usual practice is that the tubing method is not used in the hole where mud flush has been circulated during drilling. Like every other generality, this one has exceptions. For instance, one of the large companies in the Midway field used the tubing method in cementing water strings in a rotary-drilled hole. When this company has finished making the hole and is ready to set casing, the drill pipe is pulled out and the tubing stood in the derrick before the casing is started. The tubing may then be inserted far more quickly after the casing is all in the hole than would be possible if it had to be inserted by single joints.

Fig. 69—Shell cementing outfit at work
—Photo Courtesy of United States Bureau of Mines.

Cementing by tubing method with Scott outfit.—The Scott cementing equipment is used in connection with the tubing method, but the mixing and pumping mechanism may be and, as a matter of fact, is used for cementing without the use of tubing.

In cementing with the Scott outfit the first step as in all other methods of cementing, is to get circulation. This is done either with pumps at the well or with the cementing pumps. Sufficient water must be stored in the temporary tanks at the well to mix the cement and to displace all the cement from the tubing, and more water than this, either in tanks or in a reliable pipe-line system, is desirable for reasons given later. The outfit is set up near the derrick and connected with the local steam and water supply lines.

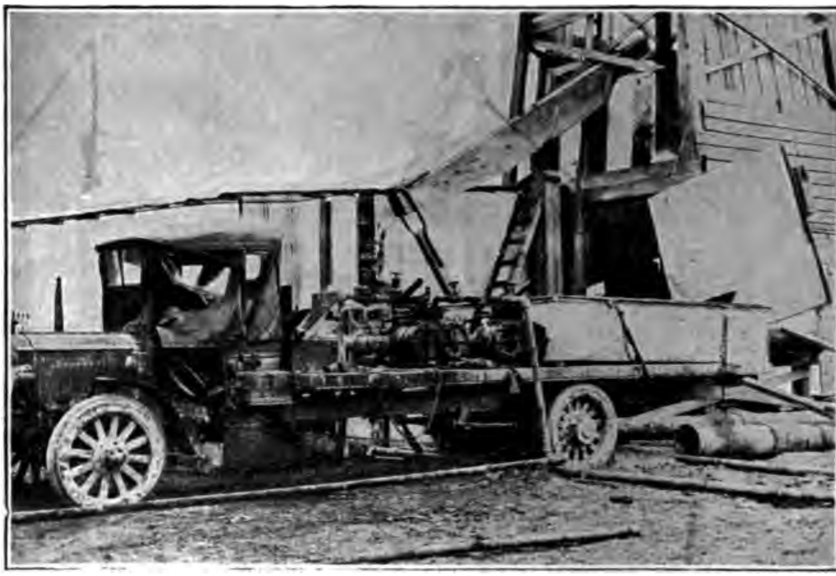


Fig. 70—Perkins cementing outfit with steam and water connections made —Photo Courtesy of United States Bureau of Mines.

A small platform is built beside the mixing machine and with a walk to the ground. This must be so arranged and the dry cement so placed that there will be no delay in feeding the mixture. As stated this machine handles a ton of cement, or 20 sacks, every two and one-half or three minutes; that is a sack every eight or nine seconds. All wires or strings must be taken off the sacks before mixing is started. It has been found advisable to have the cement handled by four men, two working at a time and relieving each other at frequent intervals. If more than two are dumping cement at a time they get in each others way and retard rather than accelerate the work. When everything is in readiness, clear water is

pumped into the tubing at a, Fig. 64, until returns flow from the relief pipe b at the casing head. The relief cock is then closed with the pump still operating and with the casing 3 or 4 feet off bottom. This should start the circulation around the casing as shown in view B, Fig. 64. Water is then started through the mixer by opening valves e, d, and a, Fig. 65, and closing stopcock b. The mixing engine g and the pump are started and the dumping of the cement into the hopper is commenced. The most satisfactory consistency for the cement mixture is determined by experience. If the mixture is sufficiently thin to be readily handled by the pumps it has an excess of water. A cement should never be mixed any thinner than this unless an effort is being made to force it back into sand, or some other such object is in view. Even the thickest mixture that can be handled by the pumps has a considerable excess of water. This method of estimating the fluidity is rough, but satisfactory. A small excess of water doubtless retards the setting of the cement, but does not weaken it to a dangerous degree.

Before actual cementing is commenced, a computation must be made so that the operator will know how many inches of water must be pumped out of the gage tank to equal the volume of the string of tubing. If the gage tank regularly mounted on the outfit has insufficient capacity for any particular job, an auxiliary tank must be set. If such an auxiliary tank is placed near enough to the pump the water may be drawn from it by merely dropping the 3-inch suction hose into it, thus reducing the amount of pipefitting. After all the cement has been mixed and pumped into the tubing the computed volume of water with usually a small excess, 10 per cent or less, is pumped on top of the cement (C, Fig.65). This is accomplished by closing c and h (Fig. 65 and gaging the water in the tank at the same time. In this way the water passes through the mixer and flushes it clean. When this is accomplished stops b and f are opened and a, d, and e are closed, thus by-passing the mixer and sending the water directly to the pump. When all the wash water is in, the casing is set firmly on the bottom of the hole. Under normal conditions this will stall the pumps. By opening the relief valve b (see Fig. 64 and c, Fig. 65) at the casing head all cement that may have remained either in the tubing or in the casing above the bottom of the tubing will be washed out by merely keeping the pump going.

After getting circulation at the beginning of the job it is unnecessary to stop the pump or the movement of the cement or circulating fluids until the job is entirely completed and the casing safely landed. If the operator does not wish to drill any cement out of the casing the tubing may be lowered to within a few inches or a foot of the bottom and all remaining cement flushed out by water being pumped into the tubing. Notwithstanding the difference in the specific gravities of cement and water, it is a remarkable fact that a large slug of liquid cement with water both above and below it may be pumped down a string of 3-inch tubing, and if desired can be pumped again to the surface through the space between the tubing and the casing without excessive intermingling between the cement and the water.

It must be borne in mind that no barrier, not even a cement sack, is used between the cement and the water in this process. A striking instance of pumping cement back to the surface between the tubing and the casing occurred at one of the Pacific Midway Oil Company's wells in the Sunset oil field where liquid cement was pumped into a 10-inch hole, about 1600 feet deep, through tubing. It was desirable in this particular well to pump in all the cement that the hole would take, so 18 tons (360 sacks) were mixed and pumped in. Of this amount 2 or 3 tons were washed back to the surface. When the cement came back to the surface it was in such usable condition that a tank was placed to catch it. The tank full of liquid cement was hauled to a garage on the property where the cement was mixed with sand and used for a concrete floor in the building. This condition of the cement after being returned to the surface is the rule, not the exception.

Of course, if the tubing happened to extend only a few inches the liquid cement at the bottom of the hole, only those few inches of cement would be washed back, and the cement might be so diluted on reaching the surface that it would not set; but where, say, a ton or more cement is involved, it may be washed back to the surface in fair condition. In most instances of this kind there is no useful purpose to which the returned cement may be put, so it is usually wasted. Fortunately it is usually possible to estimate rather closely the requirements of the particular job.

The reader may wonder why so much discussion should be devoted to the setting of the returned cement when the chief con-

cern is how it sets underground. One important reason is that if the cement sets after being returned to the surface, any failure to set underground can not logically be attributed to the character of the cement nor to the method of mixing and placing it.

Special method of mixing cement.—The Shell Company of California uses an ordinary concrete mixer fastened in the discharging position. The mixer is set to dump into a large mixing box about 2 feet square in cross section, and approximately 20 feet long (Fig. 69). A hose discharges water into the mixer continually as the cement is dumped in. Men with mortar hoes finish mixing the liquid cement as it travels from the concrete mixer at one end of the long box to the 6-inch suction at the other. From the box the cement is taken by the pumps and delivered to the well.

The two pumps shown in the left foreground of Fig. 69 are mounted on a low truck. One pump is for low pressure and the other for high pressure, and they are 10x6x12 inches, and 10x3x12 inches in size, respectively. The suction manifold is so connected that it will take either cement from the long box or water from a 3-inch connection into the same manifold. The discharge manifold and the steam connection to these pumps are so arranged that the operator may change from the low to the high pressure pump, or vice versa, without stopping the flow of liquid through the tubing.

Some companies have a hose connected to the pump-discharge manifold so that the cement may be picked up by the suction and circulated through the pump back into a mixing box, thus making the pump serve also as a mixer. This method increases the wear and tear on the pump and necessitates mixing all of the cement before putting any of it into the well.

Use of one-plug method with tubing.—A variation of the tubing method not extensively used at present consist in placing a swaged nipple on the bottom of the tubing and using a wooden bullet-shaped plug, having a disk of rubber belting or leather nailed to the flat end. This plug, point down, is inserted into the tubing on top of the column of cement ,and is pumped down with water in the usual way. The plug will stop when it reaches the swage nipple, thus stalling the pumps and indicating the end point and affording a check on the computations. This check is the one advantage over the common method as described above. The disadvantages are as follows:

1. Cement often adheres to the sides of the tubing and subsequently settles on top of the plug, or else the plug works down into the cement leaving as much as 6 or 7 joints of the tubing filled with cement. The tubing thus filled either has to be junked or else the cement has to be drilled out at considerable expense.

2. It is impossible to wash cement out of the bottom of the tubing or casing after the latter has set.

3. If circulation is interrupted, all cement not already back of the casing is left inside of it to be drilled out.

Use of the Baker cement container.—The "Baker cement container" is a device to be used under certain conditions when cementing with tubing. The container is primarily designed to use when circulation may be obtained, but when it is impossible to get a tight seat for casing on the bottom of the hole. This condition may be caused by lost tools which have been side tracked and subsequently fallen in against the casing, or the casing may have become "collar bound" so it may be removed 5 or 10 feet, but not enough to clear the couplings. If the cementing job be attempted under such conditions by the ordinary tubing method, or any of the other methods, an opportunity is afforded for the cement to runback into the hole from behind the casing when the job is allowed to stand.

The container is built of cast iron and is attached to the bottom of the tubing by a left hand nipple "a," Fig. 66 D. This nipple connects with the lower cone shaped part of the container "b." When the container has been lowered to the shoe joint, or as near the bottom of the casing as may be desirable, pulling the container up a few inches or a foot is sufficient to cause the slips "c" to wedge against the inside of the casing, holding the upper section of the plug firmly in the casing. Thus the rubber "d" is spread by the cone-shaped base "f," making tight seal between the plug and the casing. When the cement is pumped down the tubing it will readily pass the valve "e" which is seated by a spiral spring. The cement can not, however, pass back through this valve or around the container to get above it, and must therefore pass around the casing shoe and follow the course of circulation.

When all the cement has been pumped in, the tubing is disconnected from the plug by unscrewing the left hand nipple "a." Any residual cement in the tubing may be pumped out and to the surface, just as in the ordinary tubing method. The container is

prevented from slipping down the casing after being disconnected from the tubing only by the friction hold of the slips and the pressure of the cement on the bottom of the container. However, if the cement has not pressure enough to hold the container in place, not much is likely to run back into the hole. As the containers is built of light cast iron it is easily drilled up after the cement has set.

Advantages of tubing method.—The advantages of the tubing method may be summarized as follows:

1. The method requires less time after the initial wetting of the cement to completion of the job than any other method yet devised.
2. The operator can leave any desired quantity of cement inside the casing.
3. The storage space required for wash water is less than that required for the casing method of cementing.
4. When a standard-tool hole is to be cemented by the tubing method the volume of water unavoidably circulated around the casing ahead of the cement is only the contents of the string of tubing. This is a considerable advantage if the formation back of the pipe has a tendency to cave.

Disadvantages of tubing method.—Disadvantages of tubing method may be enumerated as follows:

1. Time is required to run in a string of tubing. This usually has to be laid down after the job in single joints and rolled away from the rig to permit unloading of pipe for the oil string, as well as other equipment.
2. Although the tubing method is quicker than the casing method after the cement is wet the aggregate time required to do the job is considerably greater on account of handling the tubing. For this reason some form of casing method is very popular among operators for mud flush holes—particularly for holes drilled with rotary tools. This is because of a desire to reduce the delay to a minimum, especially in a rotary hole, as the wall of an uncased hole in California will not stand long. Also in a tubing job either the drill pipe must be laid in single joints as it is pulled out and the tubing stood up or else casing will have to be done with a string of tubing as well as a string of drill pipe standing in the derrick, impeding the work of casing the hole.

Gulf Coast Method[1]

An effective method of placing concrete for a bottom-hole job is the use of cement sacks. The concrete must be mixed to a thick consistency and the sack rolled in at the edge to form a canvas cylinder of such size that it will slide freely in the casing. The sacks of cement are pushed to the bottom and tamped into place with the tools. The process is continued until the plug is brought to the desired point. The precautions of properly cleaning the hole before work is commenced, described in the section on California practice, should be taken. If reinforcement is desired, burned-wire line may be used at intervals throughout the plug.

A successful plug has been built by using only sacks from which cement has been dumped but not shaken, thus leaving some cement adhering to the inside of the sacks and retained in the fiber of the fabric. Six or eight sacks are wadded into a bundle and pushed down the casing with the tools and finally tamped to the bottom with a string of free casing. The plug is thus built up, and when complete is held in place not only by friction but also by the weight of the casing set upon it. Only a few such jobs have been reported, but all of these have been successful.

Lineal Feet Filled By One Sack Cement Alongside of Oil Well Casings

One Sack Equals 1.1 Cubic Feet Neat Cement When Set

Size of Casing: Nominal Diameter Inches	Size of Casing: Actual Outside Diameter Inches	Diameter of Well (Excess Over Casing Diameter): 1 in.—Feet	2 ins.—Feet	3 ins.—Feet	4 ins.—Feet	5 ins.—Feet	6 ins.—Feet
4¼	4¾	19.2	8.8	5.4	3.7	2.8	2.8
4½	5	18.3	8.4	5.2	3.6	2.7	2.1
5⅝	6	15.5	7.1	4.4	3.2	2.4	1.9
6¼	6⅝	14.2	6.6	4.2	2.9	2.2	1.7
6½	7	13.5	6.3	4.0	2.8	2.1	1.7
7⅝	8	11.9	5.6	3.5	2.5	1.9	1.5
8½	8⅝	11.2	5.2	3.3	2.4	1.8	1.4
9⅝	10	9.7	4.6	2.9	2.1	1.6	1.3
10	10¾	9.0	4.3	2.8	2.0	1.5	1.2
11⅝	12	8.1	3.9	2.5	1.8	1.4	1.1
12½	13	7.5	3.6	2.3	1.7	1.3	1.0
13½	14	7.0	3.4	2.2	1.6	1.2	1.0
15½	16	6.1	3.0	1.9	1.4	1.1	0.9

[1] F. B. Tough in United States Bureau of Mines Bulletin, No. 163.

Amount of Cement Needed

The table on page 206 taken from annual report of California State Oil and Gas Supervisor gives the number of feet along the casing that will be filled by one sack of cement.

Example.—It is desired to set the 10-inch string of casing at a depth of 1230 feet so that the cement will extend back to the 1200-foot depth. It is estimated that the average diameter of the hole is 16¾ inches. From the table one sack will fill 1.2 feet so 25 sacks will be required, plus an allowance for cement left inside the casing and below the casing.

The Use of Hydraulic Lime for Shutting Off Water[1]

Realizing that well cementing as commonly practiced was not always effective, Mr. E. A. Starke, chemist, for the Standard Oil Company of California, applied himself to the problem of devising improvements. Backed by the liberal financial support and hearty co-operation of his company, Mr. Starke has done much experimental work in the laboratory and in the field with various kinds of cementing materials. If results of this work were published, they would form a valuable contribution to the literature of petroleum, and it is hoped that some day the literature may be enriched. The material in this section is used by the courtesy of the Standard Oil Company, which furnished the data, Mr. Starke making many valuable suggestions.

As outlined previously, the problem that confronted the operators was how to make a water-tight and permanent shut-off in the poorly consolidated shales and clays overlying the oil measures in some of the California fields. This work is especially difficult when there is agitation in the hole by seepage of gas or by flowing or migrating water. In the early days, in shallow territory and with otherwise favorable conditions, water could be shut off with a fair degree of satisfaction by landing a water string, as has been seen. Cementing was introduced and greatly increased the effectiveness of easy jobs and made possible others that had been formerly impossible. As drilling methods progressed, even cement was not entirely satisfactory at some wells, as it did not set. At first the

[1]F. B. Tough in United States Bureau of Mines Bulletin, No. 163.

suggestion was made that cement would not set in contact with oil. Laboratory tests demonstrated that cement will not only set in contact with oil but when mixed with a considerable quantity of oil along with the water.

If water shut-off is to be made in a well which has not entered the oil or gas sands, and if there is only one string of casing in the hole, so that pump pressure can not be applied, it may be difficult, and perhaps impossible, to get sufficient high pressure with mud to plug the pores of a gas or water sand. If the mud is excessively thick the cement tends to break through it and "channel" up the pipe instead of surrounding it with a solid mass. To thin the mud may cause a blow-out of gas which will in all probability freeze the pipe.

In general, there are three avenues of approach to the problem outlined, as follows:

1. To get a cementing material that will set under agitation and also possess the other requisites of moderate cost, ease of handling, etc.

2. To get a cementing material that will stop agitation so that Portland cement will set, and that also possesses the desirable commercial and mechanical qualities.

3. To get a cementing material that possesses qualifications of both the first and second class.

The Standard Oil Company as a result of its varied experiments, is using hydraulic lime as the material to be classed under the second of the three headings mentioned—that is, for retarding or eliminating agitation that would prevent the setting of Portland cement.

Hydraulic lime has properties differing widely from those of an ordinary hydrated building lime. The latter, when mixed with water to form putty, will remain under water in this condition indefinitely, whereas hydraulic lime sets firmly under water. The setting is gradual, and although a pat will be fairly firm after standing 24 hours in air it would probably require 18 to 24 days to set firmly under water. This test may be made in an ordinary drinking glass, and perhaps save some costly mistakes. Although such a test is a guide, the author has not sufficient data on the use of hydraulic lime to state that every lime that will set hard in water is

fit to use in shutting off water in drilling operations. An operator contemplating the use of hydraulic lime will do well to make the test mentioned and other rough tests, such as the thickening effect when dry lime is mixed with the drilling mud. All test mixtures should be allowed to set under water.

Chemical properties of hydraulic lime.—The following table, presents analysis of different brands of cement and of hydraulic lime. One is struck with the similarity of their constituents and the diversity of their proportions. The cements represented in the table are typical of the best grades of Portland cement manufactured especially for oil-well purposes, and vary from each other in chemical composition. Of course, the fineness to which a cement is ground has much to do with the time required for its setting, a feature not shown by the chemical analysis. The analyses of hydraulic lime show wide variation. The German lime although somewhat high in silica and low in iron oxide and alumina for use as Portland cement, would seemingly sinter to fair grade of natural cement. There is an essential difference between hydraulic lime and cement. Cement rock, either natural or proportioned by analysis, is sintered to incipient fusion and then ground very fine to manufacture cement. Hydraulic lime, in contrast, is burned and hydrated, but never sintered.

Chemical Analyses of Cement and Hydraulic Lime

		Brand of Portland cement			Brand or source of hydraulic lime§				
Constituent	Formula	*Golden gate cement	‡Santa Cruz oilwell cement	†Mount Diablo oilwell cement	German	Pacific Lime & Plaster Co., S. F.	Cartersville, Ga.	Mankato, Minn.	Common or quick lime
	%	%	%	%	%	%	%	%	%
Silicia	SiO_2	20.89	19.38	22.36	25.87	19.51	15.04	18.10	1.00
Ferric Oxide	Fe_2O_3	3.37	5.31	2.51	8.13	12.40	72	5.02	1.30
Alumina	Al_2O_3	7.09	7.15	7.17					
Lime	CaO	63.47	63.70	62.39	55.44	39.20	51.12	40.68	97.00
Magnesia	MgO	1.32	2.13	1.39	1.14	20.61	29.53	29.17	70
Sulphuric anhydride	SO_3	1.19	1.48	1.45	1.44	1.65	Trace	2.05	
Ignition loss		1.54	1.04	2.09	1.96	.46	3.54	4.56	
Manganese oxide	MnO							.42	
Carbon dioxide and volume.					6.02	6.17			
Specific gravity		3.12	3.20	3.12					

*Pacific Portland Cement Co., San Francisco, Cal. Analysis made by the company.
‡Santa Cruz Portland Cement Co., San Francisco, Cal. Analysis made by the company.
†Cowell Portland Cement Co., San Francisco, Cal. Analysis made by the company.
§Analysis furnished by Dr. E. A. Starke, San Francisco, Cal.

Interesting and instructive as the chemical analyses are, they do not alone furnish the knowledge of physical properties that is so important. The calcium and magnesium in hydraulic lime are in the hydrated form—$Ca(OH)_2$ and $Mg(OH)_2$—but contain no water of crystallization. The name "hydraulic" comes from the property of setting under water. Without this property a lime cannot properly be classed as a hydraulic lime. The hydraulic lime used by the Standard Oil Company is manufactured by the Pacific Lime & Plaster Company of San Francisco. It is not a natural lime, but is proportioned and mixed by analysis. Such a lime has a marked advantage over a natural hydraulic lime in that its components may be varied at will to give it special qualities for certain kinds of work, as is possible with Portland cement.

When hydraulic lime comes into contact with finely divided silica and aluminum silicates of the shales and clays, it combines to form complex gelatinous silicates the exact chemical formula of which is not known. This jelly-like mass not only swells perceptibly in setting but adheres tenaciously to the walls of the hole. Any carbon dioxide in the gas of a well will react with the calcium oxide of the lime to form chalk, the reaction causing a further swelling of the mass. When such action takes place between the grains of a sand the result is to cement the sand into a compact mass surrounding the hole. The lateral thickness of such a mass is, of course, dependent on the depth of penetration of the lime solution into the formation. It is frankly admitted that a neat hydraulic lime has a tensile and compressive strength sufficient to stop the flow of water or gas from agitating the Portland cement that is placed between the lime-plastered wall of the hole and the casing to be cemented.

Milk of lime (finely divided hydrated lime that has been steam slacked) will in some wells combine with the silicates and aluminates of the formation to form gelatinous silicates, and will prove as satisfactory as hydraulic lime. This reaction depends upon the favorable chemical and physical properties of the formation and therefore cannot be universally relied upon. If hydraulic lime containing finely divided silica and iron aluminum oxide is used, its essentials are self-contained and hence it has a far better chance to do its work under unfavorable conditions than the milk of lime and is therefore preferable.

Hydraulic lime is mixed separately with water and pumped into the well ahead of the cement. When the two-plug or Perkins system of cementing is used, the lime solution is pumped into the casing on top of the column of mud and ahead of the first plug; thus the cement follows immediately behind the lime solution in its course down the inside and up the outside of the casing. The main advantage claimed for the use of hydraulic lime is that when a solution of mud, as ordinarily used in drilling, is mixed with a solution of hydraulic lime a muddy sort of plaster is formed which so coats the formation as to greatly reduce and often prevent agitation from gas or moving water. This action takes place when the hydraulic lime passes out of the casing and mingles with the mud in the bottom of the well. The writer suggests further that this mixture of lime and mud will make a firmer bond with the formation than neat Portland cement, and that the Portland cement will in turn adhere more firmly to the mud and lime plaster than it will to the ordinary mud-smeared side of a hole.

Special uses of hydraulic lime.—If mud flush is circulated continuously as drilling progresses, the mud usually fills the pores of porous sands or gravels. Occasionally the mud runs away into such sands or gravels instead of returning to the surface. Circulation is immediately lost. Nearly every driller has either had such an experience at one time or another or knows where it has occurred, and realizes the difficulty of re-establishing circulation. Teams are often kept busy for days hauling mud and manure, sawdust, etc., to be mixed with the mud in an effort to clog the passages. The Standard Oil Company handled an obstinate hole of this kind in the Antelope Hills by mixing hydraulic lime and manure with the mud in the box. This mixture filled the channels in the sand and circulation was restored. Though the lime may have cost money, whereas the other materials were free, the difference was more than offset by the differnce in hauling and labor charges, to say nothing of the risk of allowing the hole to cave. This risk increases greatly the longer the time before circulation is restored. For work of this kind the dry lime may be shoveled into the liquid mud and mixed with shovels or hoes, and by circulating it through mud pumps. The lime need not be mixed with water and then poured into the mud.

There is still opportunity for investigation and improvement in

this phase of exclusion of water from oil and gas wells. If hydraulic lime or some other substance that will set hard after being mixed thin, is forced into each water sand when encountered, thus changing the sand to a hard lens of impervious and permanent sandstone surrounding the casing, much expense may be saved in drilling operations. It might be possible with such a system to drill wells with cable tools and use only one string of pipe, whereas under present practice one or two additional strings are used as conductor pipes and water strings. The saving thus effected would be great, provided the cost of sealing the sands could be kept moderate.

If such a process were developed, it could be applied to intermediate water, permitting simultaneous production from the oil sands above and below the water with the use of only one string of surface casing or an oil string in territory where the oil sands did not stand up well enough to make an open hole possible. To handle intermediate water by such a method would, of course, require a packer of some kind set below the upper producing sand and above the intermediate water sand. The packer would prevent the lithifying solution from entering the upper oil measures, and thus perhaps seriously affecting production.

It is the writer's hope that the foregoing discussion may not only acquaint operators with what has so far been done in the use of hydraulic lime, but may induce them to conduct further investigations bearing on the subject and to make their results known, whether successful or not. A knowledge of the limitations of a process is just as essential as an understanding of its scope.

Packers[1]

When water troubles have been narrowed down to one or a few wells, bridging, packer, or other tests may become necessary to definitely determine the source of the water, and to indicate the proper means for excluding it.

The rubber wall packer is considered a suitable testing device, though packers may also be used with hemp or other fiber as a packing material, either woven or loose, when set inside a string of casing.

Various kinds of "formation" packers (rubber, lead, or other

[1]F. B. Tough. U. S. Bureau of Mines Bull. No. 163.

material used to make a tight fit between the casing and the wall of the hole) are used in the Mid-Continent and Eastern fields for shutting off water. Generally the packing material is rubber. It is well known that rubber is soluble in petroleum and many of its fractions, and will harden under water or in the air, thus losing the elastic property that makes it valuable as a packer. Therefore its use as a permanent packing material for oil or gas wells cannot be considered. Experience has shown that gas wells frequently will blow out large chunks of the rubber packers set in them to shut off water. The only safe use of the formation packer in oil and gas wells, for any more than a temporary shut-off, is when a large quantity of hemp or fiber is used, and in addition mud fluid is circulated and allowed to remain back of the casing and above the packer. Thus, if the packer ever fails, the mud will rush into the well, making the source of the trouble evident, requiring immediate repair or plugging. Even this use is permissible only where no other means are available to accomplish the desired end.

The packers used in California practice are usually placed either on tubing or on small sizes of casing in order to restrict the diameter of the well to promote flowing. Packers are also set on casing below a leak in the water string, thus preventing the water from entering the productive part of the hole. A wall packer, in the sense that it is set in the wall of the hole and not inside another string of casing, is almost never used in the poorly consolidated shale sand clays constituting the formation overlying the oil zones in these fields.

An exception is the packer built by Mr. C. W. Stone, of Maricopa, Cal., for a special job in the Sunset field, where a flowing water sand had to be cased off in order to utilize the oil measures below. Several attempts made with the usual cementing and mudding methods gave only temporary success. A packer that proved successful was made around the shoe joint with old bull rope and bail wire. To make the packer, the shoe joint was placed with the upper end down on the derrick floor. A board at the roof made a convenient place from which to work. Hemp bull ropes were cut in 35-foot lengths and untwisted. The strands were doubled and the loop ends tightly wired to the pipe immediately under the shoe until the compressed hemp mat was flush with the outer edge of the shoe and extended entirely around the pipe. The

loose hemp was tied every two or three feet with a strand of soft rope. The packer was then complete, and, after being turned right end up, was placed at the bottom joint on the string of casing. Of course, such a packer might be placed anywhere in the string so as to set wherever most desirable. As the packer entered the hole each soft rope string was cut, thus leaving the long strands of hemp free to spread out at any enlargement of the hole. When the pipe was set any movement of the water past the packer drew the loose hemp into the passage and automatically clogged it. Mud settling on top of the packer also assisted in its effectiveness. This type of packer has three great advantages, as follows: Effectiveness; nominal cost (old bull rope and bail wire); does not occasion material difficulty if the casing is to be pulled.

Bottom water packers.—When a water sand has been penetrated at the bottom of the well below the productive formation and separated from it by a parting, it is not always easy to plug off the water so tightly that when the fluid is all pumped from the hole the plug will have sufficient strength to hold back the water. A reinforced concrete plug has proved effective in many such wells. The reinforcement consists of old wire drilling cable cut into 10-foot or 12-foot lengths. These are burned sufficiently to draw the temper. Each piece is doubled on itself and fastened with bail wire to others treated and bent in the same way. All the free ends of the cable are laid the same way in the bundle, which is of such size that it will slide freely down through the casing. These bundles are dropped into the casing with the bent ends down and the cut ends up, so that the package will not catch in the pipe and hang, for if such a wad of annealed wire ever bridges in the casing it would cause much trouble. As an extra precaution against such an occurrence, tin cans may be used over the lower end of the bundle. The cans must of course be wired on tightly. The hole is thoroughly cleaned out before the first bundle of wire line is put in. Each bundle is tamped firmly into place with the tools, a flat-bottom bit being used. This process is repeated until a firm foundation has been built and the soft wire mass wadded thoroughly into the irregularities of the hole. On top of this mass a canister containing wet concrete is then lowered, being attached to the tools with wire, and is broken up with the tools and pounded down on top of the wire line. The canister is made of light galvanized iron

four or five feet long and of any convenient diameter to suit the size of the hole. These canisters should have soldered joints and pointed bottoms to obviate any danger of catching on the sides of the casing.

Concrete of about the same consistency as for surface work is mixed in a box on the derrick floor and poured into a canister. Several canisters may be placed before more wire line is put in. The plug is thus built up of alternating layers of concrete and wire line pounded together until the hole is filled to the desired point. The plug is then allowed to set quietly with the hole full of fluid for ten days or two weeks. This method usually gives a substantial plug, but should not be used if there is much likelihood of deepening the well, as it makes a plug that is difficult to drill out.

Nearly all oil or gas wells diminish in diameter with depth, hence in plugging off bottom water, any bailer or other container used must generally be of small diameter. This necessitates more runs to cement a deep hole and is objectionable, owing to the greater amount of time required to run the bailer or container to bottom and pull it out for another trip. For example, in a 3500-foot hole 4½ inches in diameter, it is a tedious task to dump 35 to 40 sacks of cement, and very likely the first part will take its initial set before the last batch can be dumped. To avoid this difficulty a string of tubing may be run in and hung a few feet off bottom with both the hole and the tubing full of water. The entire amount of cement to be used can then be mixed in one batch and poured by a swing connection from the mixing box into the top of the tubing. Water can then be immediately run into the tubing on top of the cement. By its own weight the cement will gravitate quickly to the bottom of the hole and set there in a solid mass. This system is, of course, one variation of the tubing method as applied to bottom hole work without the use of pumps.

If the bottom water has sufficient head to make it flow, it is likely to wash the cement away before it can set, thus leaving a water channel through the plug which will wash larger and allow more and more water to pass as time goes on.

A most ingenious and highly successful scheme for handling such conditions was used by Mr. C. W. Stone of Maricopa, Cal. He collected a quantity of old hemp rope, unraveled it, and chop-

ped the strands into pieces about four inches long. These were wadded into tin containers of 4-inch stove pipe joints about three feet long. Each joint was battered in at one end to prevent the escape of the hemp. Of course, different conditions will require more or less hemp or burned wire line, but in this particular instance 12 tins of chopped hemp were put on bottom, care being taken not to break the tins. If the tins are broken at this stage of the work, the whole plan is defeated, as the hemp will be washed away by the flowing water. Four bundles of burned wire line four feet long were then run in on top of the tins, each bundle being pushed firmly to bottom with the tools. When the fourth bundle had been placed, the tools were hitched to the beam, and tamping commenced. A flat-bottom bit was used, and the tamping was continued until the wire had been firmly driven down on top of the hemp. This tamping broke the tin containers, liberating the chopped hemp which rose with the water current and lodged in the mat of wire line above. Under such conditions the hemp would naturally be carried by the water first into the more open channels, and later into the more restricted water courses, and so on until all flow stopped. More hemp and more wire line might have to be used in some jobs than in the one described. In this instance several layers were used until finally the flow of water diminished, getting less and less at each stroke of the tools until it ceased flowing altogether. A concrete cap was then placed on top of the plug and built up to the desired level. Generally these layers are made five to ten feet thick. Mr. Stone has tested these plugs by permitting them to stand 42 hours after the water level has been lowered 2000 feet in the hole and found them satisfactory.

When feasible it is good practice to drill clear through a bottom water sand and five or ten feet into the shale below, clean the hole thoroughly, and build the plug from the bottom of the hole up through the water sand and well up into the formation above. The plug then takes a position like the core of a stopcock and is subjected to lateral pressure from all sides but not to the heaving thrust exerted on a plug extending only a little way into the water sand, where reliance is placed entirely in the hold the plug may have in the overlying formation.

To indicate what the heaving tendency of a flowing water sand may be on a plug that does not extend into and form a tight seal

with the formation below the sand, assume that the bottom water rises to the ground surface in a 2000-foot hole. When all fluid is removed from the hole, the plug will be under a heaving pressure equal to the static pressure of a 2000-foot column of water. This pressure is equal to 870 pounds per square inch, or a heaving pressure of about 22 tons on a plug in an 8-inch hole.

"Bootleg Packer" System

Speaking of methods of shutting off water in the Gulf Coast fields Mr. F. B. Tough (U. S. Bureau of Mines Bull No. 163) says:

"Although effort is made to set the water string in a suitable stratum between the lowest upper water and the first oil sand, this is not always accomplished; and as 6-inch pipe is customarily used for water string in 2000-foot or 2500-foot territory, such failure becomes serious. It would probably be difficult, if not impossible, in many wells to loosen such a string of casing even were it handled without cementing, and to set or cement the string of 4½-inch casing would permit nothing larger than 3-inch pipe in the sands, thus restricting the size of the hole to an inconveniently small diameter. To obviate such a condition the 'bootleg' has been devised and is often used but is not recommended.

"The 'bootleg' (Fig. 71) is made of canvas or leather riveted or screwed into the shape of an upturned truncated cone with the smaller end the same size as the exterior of the string of pipe on which it is to rest. The upper end is larger, so as to rest against the wall of the hole, but must, of course, be small enough to collapse and pass through the next larger pipe shown as of 6-inch diameter in the figure. The bottom of the 'bootleg' is fastened with wire wrapping to the 4½-inch casing just above a coupling and is placed at such point on the string that it will set in a stratum of gumbo when the pipe rests on the bottom. The gumbo must, of course, be below the water sand, and ideal conditions require a bed of shale above the gumbo to furnish the requisite cavings.

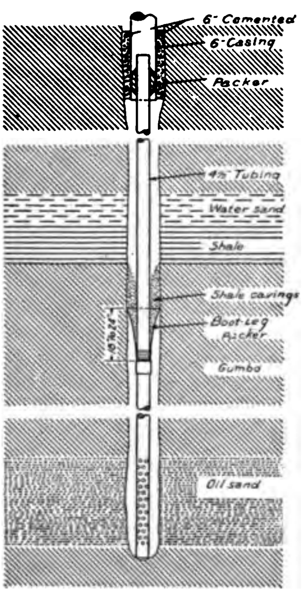


Fig. 71—"Bootleg" Packer. Made of canvas or leather.

"The shale cuttings and mud are expected to settle around the 'bootleg' from above and make a tight joint between the casing and the gumbo. The action is similar to starting a bridge in a hole by using a forked stick.

Neither the bootleg nor the forked stick hold any considerable weight; merely enough to arrest the settling of debris until the latter commences to bridge. Sometimes in order to save casing the inner string, shown as of 4½-inch diameter in the figure, is fitted with a packer to set in the bottom joint of the 6-inch pipe. The upper part of the 4½-inch string is then backed off at a left-hand nipple above the packer and pulled out.

"Of course, a 'bootleg' job should be tested as far as possible, but a thoroughly satisfactory test is not possible. If the well is pumped and brought in as a clean producer, then the 'bootleg' has probably been successful; but if some water comes with the oil, there is always a doubt as to whether the 'bootleg' is leaking or whether the water is encroaching on the oil sands, or whether it is working around 4½ to -inch packer, and the very nature of the device precludes testing its effectiveness before drilling into the oil-bearing strata. No matter which way the water gains access to the well, the string with the 'bootleg' on it must be pulled out. Then either another bootleg must be tried or the 4½-inch string must be set as a water string, which is by far the preferable method.

"When water has not been properly shut off it sometimes shows immediately, but even then the well is usually pumped for a while with the hope that the cuttings will settle around the 'bootleg' and make a successful job. On the other hand, if the well has sufficient gas pressure to hold back the inflow of water temporarily, several days or weeks may elapse before the gas pressure is dissipated sufficiently to permit the ingress of water. The water will then probably make its appearance in the form of an emulsion. At this stage of the well's life, water on the sands is more serious than before the gas pressure is dissipated, because the sands will take more water and will not have the expelling force of the gas to remove it when the repair work has been completed.

"To pull the 4½-inch string may or may not be possible according to the amount of friction on the string and other factors. Even if the 4½-inch string is loosened, it cannot be removed without letting the mud from behind it into the oil sands, which are, as stated, in a most receptive condition and will probably never relinquish all of the mud and water thus admitted. Such results will not always follow the use of a 'bootleg.' There are doubtless walls in which water is shut off with such a device now producing in the Gulf Coast fields after a long period of activity, never having shown any serious volume of water. Nevertheless when a company attempts to use a 'bootleg' it takes a chance of spoiling valuable property and diminishing the gross oil recovered from it, merely to make a small saving in first cost."

The writer has had considerable experience with bootleg packers and does not share Mr. Tough's pessimistic views concerning their use. Used in the Coastal fields, where almost all formations tend to be soft and cavey, the bootleg packer shuts off water almost invariably if properly applied.

Shutting Off Water by the Tamping Method[1]

To those familiar with the oil business it is unnecessary to state that the cementing process, with its several mechanical variations, holds the center of the stage in California. The mud-laden fluid method is being tried out with apparent success in the Oklahoma fields, and will no doubt play an important part in the economics of the petroleum and gas industry.

I have recently noticed several failures with cement which illustrate the necessity of caution. A 10-inch string was cemented but did not set. An 8¼-inch string was also run in and cemented, and another failure was the result. The maangement grew suspicious and experimented with samples of the cement at the surface, using water from the hole and also from their water well in the tests. None of the samples set. The tests would have been more complete had they included samples mixed with distilled or other suitable water so that the blame could be fixed on either the dissolved salts in the water or on the cement itself. Of course it was unfortunate that the tests were not made before the cementing operations began, and the moral is apparent. Citing another case of failure, a 10-inch string was cemented in a rotary drilled hole with 21 tons of cement, after which water was found coming in around the shoe. It is believed that the rotary mud was not thoroughly washed from the hole before the cement was introduced and that the cement did not make a suitable bond with the walls at all points of the circumference of the hole. This probably allowed the water under pressure to form channels around the outside of the mass of hard cement. It might be argued that the mud-laden fluid back of the cement should hold the water. It would be quite likely to do this if a suitable shoe had been driven into a tapered hole. Another point to consider is the condition of the contact of the cement and mud, as dilution of the cement with mud may form a zone of weakness. In the case mentioned the mud probably had not packed around the casing for any distance, and the resistance to water could not be as great as in the regular use of the mud-laden method. The reason for using such a large quantity of cement was that it was known that the rotary had made an exceptionally large hole, which was shown by the drill-pipe being bent considerably.

There are some who believe that the old-fashioned formation

[1]H. W. Bell, in Western Engineering Vol. 8, March, 1917, pp. 88-90.

shut-off is better than the ordinary cementing practice. When a long, suitable shoe is driven into a sticky clay, and judgment is used, the chances for success are excellent. Ordinarily the bottom of the hole is not tapered when using cement. Why not combine the two methods and drive the casing into a tapered hole after, or simultaneously with, the introduction of cement on the outside? There are then two chances of success, and the cement would at least protect some of the casing from corrosion. The fact that cement will not harden, when kept agitated by the action of gas or water, is the cause of a large proportion of the failures.

The principal object of this communication is to obtain information, if possible, concerning facts or opinions on another method of handling the water problem in the oil fields. I have never seen any data in print regarding the process, and I find that few oil men are familiar with it. As I understand that it was invented nearly twenty years ago and used successfully for a time, I am interested in learning the reason for its disappearance, particularly because I have recently seen the principle successfully and easily applied. The process, called tamping, is said to have been first used in the Fullerton field by William Plotts. H. G. Anderson of Coalinga, an oil man of long experience, has used it successfully and believes it to be an excellent and perhaps the best method of excluding water, especially bottom water. He knows of no reason for discarding it except that the inconvenience of "spudding" the pipe puts it in disfavor with most of the drillers and therefore it was not given a fair chance.

In the tamping method, either oil sand or a mixture of sand and resin is used. A mixture of one part resin to seven parts sand has been found good. The underground temperature is usually high enough to soften the fine particles of resin readily and they then form a somewhat plastic combination with the sand. The action of "spudding" a string of casing, as this mixture is fed between the two casings, makes a tough water-resisting filling material which seems to bond well with the walls whether mud is present or not. The tamping force of a heavy string of casing causes an adjustment of all the material in the hole with the effect of excluding the water. Proper depth of tamping must be considered and the material must be fed slowly. It is said that, when necessary to remove casing after it has been tamped, it can be accomplished with but little dam-

age to any formation that must be preserved intact around the hole. If a large proportion of resin is used, it will probably be necessary to use iron scraps or other hard substances to facilitate the redrilling.

It seems that the process was originally used as a sort of secondary method or one of last resort. It was probably applied after a formation shut-off had failed, or after casing had been perforated by corrosion, or for shutting off bottm water. In a recent case the 10-inch casing was cemented and found satisfactory. Several months later, when the well was producing, water broke in around the shoe. The oil string was 8¼-inch, so 6¼-inch casing was inserted and tamped off by spudding the 8¼-inch string to a point above the 10-inch shoe. It appears that this method might be used at the start if its advantages were decided enough to offset a decrease in the size of the casing. It also appears, however, that it may be found possible to use but one string in a well. If a rotary well is drilled to accommodate, say, 10-inch casing, this string could be put in, then 8¼-inch casing inserted and tamped off. The 10-inch casing could be withdrawn and the 8¼-inch casing would commonly be left as the water string. If conditions were favorable for drilling into the water sand with the rotary it seems possible that but one string would have to be used. The tamping can be carried to a point as high as desirable so that all of the important strata could be sealed, and the tamping could be broken at any points to allow production from any zone. If one string was used and it was desired to produce from, or leave the well in readiness to produce from several sands, the mechanical details could, no doubt, be arranged satisfactorily. If it were deemed necessary, "stops" to break the tamping could be placed above the oil sands, although this has been found unnecessary when the hole is not too much larger than the tamping string. The stop could be made of hemp and arranged so that the tamping string would spread them when coming down. If these were used there would have to be a system of placing them by unscrewing and inserting again with an additional "stop." Special steel collars and left-hand threads might be employed to advantage. After tamping had been done above the last productive measure, the filling could be carried to the surface or near it and, if this was properly done, no water could

come in contact with the casing. It is believed that corrosion of the casing would be negligible.

When bottom water is encountered, the following method has been used with success against a strong flow of water that could not be curbed by the ordinary method of stuffing before cementing. A string of suitable size, smaller than that which entered the bottom water is inserted to bottom. It should be perforated for the bottom water and carry a valved heaving plug above the perforations. The tamping is started on the outside and the flow is handled throug hthe plug. After finishing the tamping the valve in the plug is closed and the water is confined below it. A little cement may be dumped on top of the plug and the casing cut and removed.

It seems that the tamping method could be used with decided advantage in many cases, that it was the victim of the early-day drillers, and that it is well worth consideration of some of our oil well problems.

Comment by William J. Travers, Fullerton, Calif.: "I have used the tamping process on about 30 wells in the Olinda district. I regard it as the ideal method of shutting off water. Cement is easier to place but is liable to failure from (1) the cement failing to set (2) pipe leakage, (3) well walls slacking away after the cement sets and the well is put on the beam. Tamping avoids these and has the additional advantage when begun at the oil sand and carried to the top of the hole, of keeping all the water in the formation originally found, and not allowing it to penetrate to the lower levels. It also avoids all danger of collapse and "elbowed" pipe, resulting from shifting formation.

"I usually tamp the string of casing with which the well is finished. Where a well has 6, 8, 10 and 12½-inch casings in the hole, the 8, 10 and 12½-inch strings are removed in turn as the well is tamped. I use cement and sand the first hundred feet, and then sand only. I prefer to have several hundred feet of sand tamped below the last water, but I know from actual experience that in one well 40 feet of sand has held a 1600-foot head of water for the past 13 years, and that sand even under slight pressure will hold water. This fact may be observed when sand is placed in a leaky tank. My deepest tamping job was begun at 3600 feet. When stops are needed, I use a canvas bag placed on the lower joint of the tamping

string. This bag fills with sand and cement and forms an excellent bridge.

"I have never used resin. I formerly used a mixture of clay and sand, but now use only sand, except as noted for the first hundred feet. I notice on page 213 of the report of the Oil and Gas Supervisor that tamping can be used only when the casings can be removed. This would be desirable, to be sure, but I had occasion to tamp one well with two solid strings of 10-inch 42-pound casing and 8¼-inch 36-pound casing, which were perforated and a 4½-inch string tamped in with a 6-inch pipe."

METHODS OF TESTING THE WATER SHUT-OFF

The following suggestions have been issued by the California State Mining Bureau:

Measurements to the bottom of the hole and to the bottom of the casing shoe must be carefully checked before the casing is landed or cemented and before notifying the deputy supervisor of intention to test. A steel tape should be used in determining the distance that the sand line or drilling line measures over the derrick.

Casing must be tested by bailing the well to a safe depth, depending on the collapsing strength of the casing, before drilling below the shoe. Old casing may collapse with less pressure than that indicated for new casing. Testing by applying pump pressure inside the casing will not always reveal leaks.

Drilling out the cement or other material in the casing must be done carefully to avoid damage to the "shut-off." The drill should be run only far enough to go through the cement and below the shoe. A distance of from five to ten feet below the shoe will be ample. Drilling too far below the shoe may cause complications that will prevent a positive test.

Bailing should, if possible, continue until all fluid is removed from the hole, unless there is danger of collapsing the casing. It is advisable to use the bailer until it brings up nothing but mud on the last run, then allow the well to stand an hour or more and again bail to remove the water that has sprayed on the inside of the casing and drained to the bottom. When a well is in such condition that it cannot be bailed dry with safety, the fluid should be lowered to a certain depth by running the bailer to that depth until no more fluid is raised. A permanent target should be placed on the line

to mark the bailing point. If both oil and water are present in a well that cannot be bailed dry, it may be necessary to remove the water by bailing from the bottom of the well until the bailer fails to bring up water. The well should then be allowed to stand several hours and the bailer lowered to determine the point where it reaches water; at this point the well is ready for inspection by the deputy supervisor. Afterward the water may be removed by bailing from the bottom of the well, account being kept of the amount bailed out. It may be necessary to repeat this process several times in order to determine whether the water is being exhausted. In case of high pressure and flow of gas or in the case of 'heaving' formation, it is probable that the well can be tested only by pumping.

When a tight or closed bailer is used in a deep well, some form of outlet or valve should be provided in order to relieve the pressure that may endanger the lives of persons in the derrick when the bailer comes out of the well. A leaky bailer should not be used in testing.

A well must stand at least twelve hours without any bailing before it is to be witnessed by a representative of the bureau. A longer time is preferable.

The law requires that the Bureau be given written notice at least five days before a test. It will save time for both the operators and the state officials if additional notice of the exact time be given by telephone.

CASING TESTER AND BAILER FOR LOCATING CASING LEAKS

By plugging in the shoe of the casing and making bailing tests, the existence of a casing leak and the rate of flow can be detected, says the California Mining Bureau in a bulletin recently issued.

By the use of a casing tester (see Fig. 72) the position of the leak, as well as the rate of flow, can be detected. The accompanying sketches show how the tester looks and how it works.

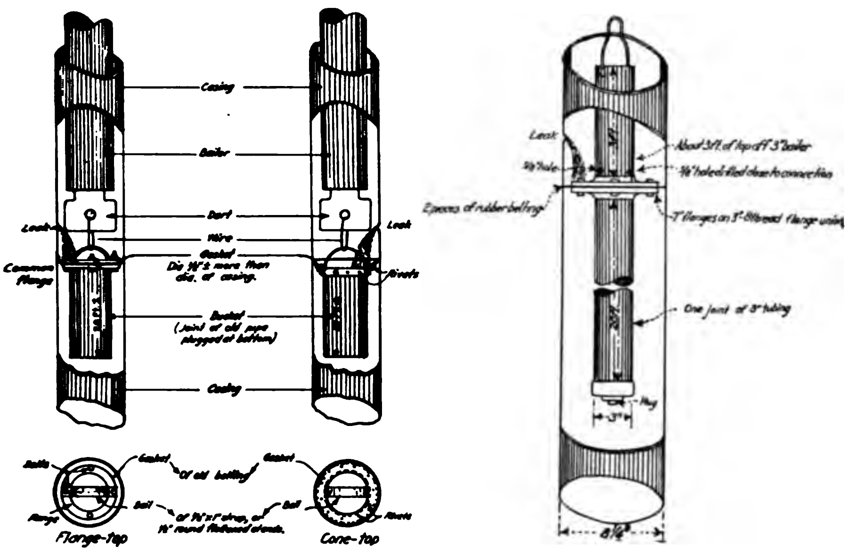
Causes of casing leaks are usually one or more of the following: Insufficient tightening of casing, collapse, defective wells, corrosion, line wear, or shifting formations.

In a drilling well considerable time and expense can be saved

by testing a water string, if cemented, before the plug is drilled out for test of shut-off.

If this program is not followed, the test for water shut-off is not only inconclusive, but it may be necessary to again plug the shoe of the casing with cement or run a casing tester.

A casing tester, or swab bailer, as it is sometimes called, can be used to locate definitely any one of a number of leaks. There are a number of variations in the so-called swab bailer or casing tester.



Swab Bailer or Casing Tester
Fig. 72.

All testers have a closed bottom. The casing must be bailed free of fluid below the depth to be tested. The tester is to run to a predetermined depth and allowed to stand for a given length of time. When the tester is removed, the amount of fluid therein can be measured and the rate of leakage reduced to flow for 12 or 24-hour periods.

When the position of the leak has been determined, the next thing to do is to repair it. The method of repair depends to a great extent upon the nature of the leak.

A number of instances of insufficiently tightened casing have come to our attention. In most cases this is simply due to lack of care when the casing is put into the well.

The following are given as examples of testing and repairing casing leaks:

In well No. 7 of the Standard Oil Company, Sec. 8, T. 30S., R. 22 E., M. D. B. & M., 10-inch casing was cemented at 2355 feet with 160 sacks cement by the Perkins method. The crew reported that a casing tester was run to 1800 feet and it was found that the casing was leaking. The casing was then screwed up 30 inches and water was found to be shut off.

A leak was found at 1460 feet in 6¼-inch casing in well No. M-C 36 of Standard Oil Company, Sec. 17, T. 3 S., R. 10 W., S. B. B. & M. The 6¼-inch casing, landed at 3993 feet, was ripped with a ⅜-inch rip, 8 inches long, at 1550 feet and 50 sacks of cement was dumped through the rip into the space between the 6¼-inch and 8-¼inch casings, by the Perkins method. The plug in the 6¼-inch casing was drilled out from 1540 feet to 1560 feet, and the wooden plugs (used for bridge) pushed down to 2950 feet with 4-inch rotary pipe. Water was bailed to 2000 feet. The hole stood 51 hours, and at the end of that period showed a rise of one foot of water. The repair work was usccessful.

In well No. 3 of the Southern Pacific Company, Fuel Oil Department, Sec. 19, T. 20 S., R. 15 E., M. D. B. & M., a leak was found in the 8¼-inch casing, cemented at 1430 feet. The leak was repaired by setting a packer at 1394 feet. The fluid level before setting packer was 90 feet from the top, and after setting packer it was 600 feet from top. After producing the well one week, the fluid level dropped to 1200 feet, the old fluid level of the well.

CHAPTER III.

OPERATION OF PROPERTIES AND HANDLING OF PRODUCTION

Introduction.—The operation of properties and handling of production is so broad a subject that it is exceedingly difficult to know exactly how to proceed in order to group the material in such a manner that all persons interested in the subject can easily get the data most desired.

It has been thought best first to take up the problems which are encountered in the bringing in of flowing wells, then to give a short treatise on swabbing, to go from that to the blowing of wells with compressed air; and lastly to treat of the handling of pumping wells and the problems arising therefrom.

In every case the various phases are taken up by treating the problems and their solution in distinct localities. This is deemed much preferable to making an attempt to treat these subjects in a broad and general way, thereby benefitting no one specificially.

THE CONTROLLING OF GUSHERS AND GASSERS

The Control Casing Head

Throughout the Mid-Continent fields the control casing head finds extensive use in the "bringing in" of oil and gas wells. It is thoroughly described by its inventor, Mr. Alfred Heggem (Trans. A. I. M. E.) as follows:

With the bottom of the casing securely in place, and forming a pressure-tight, non-leaking joint, the top of the casing remains to be considered in the matter of control. Valves of various types were tried, and while not accomplishing as much as was desired, they were in many cases a necessity.

In its highest form, this type of equipment consisted of a gate valve, of inside diameter greater than that of the casing, surmounted

by the casing head, the two being connected by a short nipple. This arrangement provided the usual casing head to which flow connections could be made and through which the usual drilling operations could be conducted. In addition, the gate valve furnished means by which the well could be shut in when the drilling tools were removed.

It was thought by many that a gate valve so placed on the head of a well insured control, but in practice many failures of this arrangement demonstrated that it did not safeguard either life or

Fig. 73—Control Casing Head

property and really caused a false feeling of safety. In fact, because of inability to close the valve promptly at a critical moment, oil or gas has become ignited and burned with great violence, making approach to the well impossible. The gate valve had to be removed by shooting off with a cannon ball, or other means, before the well, thus supposedly safeguarded, could be brought under control.

Requirements for efficient controlling device.—A proper closing and controlling device for the head of an oil or gas well must meet the following requirements: it must permit drilling operations to be carried on without interference; permit of immediate and tight closing; control the flow without back pressure; insure safety to

workmen; be simple in construction; compact in size; sufficiently strong to control maximum pressures; proof against injury in handling; unaffected by sand; and unaffected by fire.

The control casing head—The "control casing head," combining the functions of a gate valve and a casing head, was designed to meet these requirements, which are considered necessary to safeguard life and property during the operations of well drilling.

This device is similar in general appearance and size to the common type of casing head in general use (Fig. 73). It can be placed above or below the derrick floor, at the will of the operator, and is arranged to receive the standard fittings commonly used with casing heads. The top opening is threaded to receive a drilling nipple or other top connections usually employed in gas wells.

The interior of the head is bored out to a true cylinderical form into which is closely fitted the plug or valve (Fig. 74). This valve is open at one end to provide a lateral passage for the oil or gas; the other end is reduced in diameter to form a stem, which extends through a suitable stuffing box, and by which the valve may be operated. On the stem side of the valve a flat surface, or flange fits closely against the base of the stuffing box, making a tight joint, thereby to a large degree relieving the stuffing box of duty in preventing leakage. The extending stem is hexagonal in form to accommodate a wrench, but a tranverse hole through it provides a more convenient means ot operating by use of a bar of iron, such as a bolt or piece of 1-inch pipe.

To provide for the convenient operation of the valve at a distance, when the casing head is below the floor or is otherwise not readily accessible, the end of the stem is bored out and threaded to take an extension of standard 2-inch pipe.

The back of the valve is broad enough to close completely either top or bottom opening in the body, and provide sufficient lap to prevent leaking.

On each side of the back of the valve is a groove ,or notch, of sufficient size to encompass the drilling line, sand line, or torpedo line. By this provision the valve, when closed, while completely shutting in any flow, does not injure the line.

By means of the end opening, as well as by recessing the back of the valve, the pressures within the casing head are to a large degree counterbalanced, making the operation of the valve easy.

The device is simple, consisting of but four pieces, and having but one moving piece. It cannot be damaged by any of the usual drilling operations or by rough handling.

Stops are provided within the body to prevent the valve from being turned too far in either direction. With the valves in normal position but a quarter turn of the stem is required to close the top or the bottom opening, turning the flow into the tanks or entirely shutting in a well.

The control casing head is used in much the same manner as gate valves and common casing heads, but it has many special uses that have developed largely from experience with the great number in operation in various oil fields.

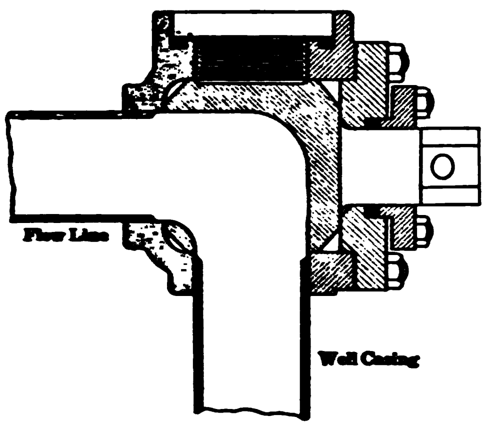


Fig. 74—Control casing head on well showing the curved deflecting surface to change gradually the direction of flow and prevent the mechanical vaporization of the oil. The area of the passage through the casing head being greater than that of the casing insures a reduced velocity and prevents frictional back pressure on the well

The control of wildcat wells.—When drilling a well in unknown territory it is not possible to foresee what conditions may be encountered, and many wells so drilled have "gone wild" with great destruction of property property and in a number of cases with loss of life.

Some such wells have ruined fields of good prospective value by letting water in on the oil in such quantities as to render further operations in that district unprofitable.

For such cases it is desirable to place a control casing head on the first string of casing landed in the well and maintain it there through all subsequent drilling operations. This insures that the well can be kept under control, and if at any time oil or gas is encountered unexpectedly the well can be instantly shut in until provision is made for taking care of the yield. It is not necessary to withdraw the tools as the valve will close tightly around the line, so no time need be lost in bringing the well under control.

Also, with the flow stopped or controlled, there is no force acting to expel the tools, so this danger is avoided.

When a new string of casing is set inside of the one carrying the controlling device, the string may be set with the top below the head in order not to interfere with the free action of the valve; or the control head may be set on the inner string by using a swage nipple; or a smaller head of suitable size may be used.

If it is desired to shut in gas between the two strings of casing, a packing ring may be screwed into the larger casing head and a gas-tight joint made on the outside of the inner casing.

This process may be repeated with each string of casing inserted in the well. Of course where several heads are used on the same well, the larger ones should be placed below the derrick floor in order that the last casing head may not extend to such a height above the floor as to interfere with the ready wrenching of the tools or limit the length of temper screw that may be let out.

Use of control head in established oil field.—When drilling in an established field the control casing head is placed on the last string of the casing to be seated in the well. Since it is about the same height as the common casing head, it does not interfere with the wrenching of the tools or other drilling operations.

If a pocket of gas is encountered, the well may be instantly shut in without removing the tools, all fires may be safely extinguished and the boiler moved back to a safe distance, when drilling may be resumed.

On reaching the oil sand, if the well starts to flow it may be shut in, or if flow-line connections have been made the entire flow may be diverted to the flow tank. When the flow ceases, drilling may be resumed and continued without loss of time until the well again starts to flow.

If the well flows continuously, an oil saver is placed on the line immediately above the control casing head, while same is closed. When ready, the valve is turned to allow the oil saver to enter the seat in the top of the casing head. This may be accomplished without loss of oil, wells producing as high as 10,000 and 12,000 barrels of oil per day having been drilled in this manner without and oil showing on the derrick.

The prevention of waste of oil in drilling means not only a saving to the operator, but also the reduction of the fire hazard to a

minimum. The driller and "tool dresser" do not get drenched in oil and thereby risk fatal injury by fire, which under the usual conditions prevailing before the introduction of the control casing head occurred with appalling frequency.

Moving the boiler away from the rig did not remove all hazard, for cases are known in which a tool dresser, in clothes soaked with oil from a spraying well, has approached the boiler to try the water cocks and had the flames from under the boiler set fire to his clothing. Such accidents are almost always fatal.

The control head useful in shooting an oil well.—It often happens that, while a well still flows or sprays oil continuously, the yield has reduced to such an extent that shooting must be resorted to in order to save the well. There are, in fact, many reasons for shooting a well, even though the flow pressure is such as to make the placing of the shot a hazardous undertaking.

In the history of the petroleum industry, one finds that frequently a well would flow during the placing of a shot, causing the shell to be ejected from the well to explode in the derrick, with frightful loss of life and property.

The use of the control casing head on the inner string of casing makes the shooting of any well a safe operation. The shell containing the "shot" is lowered until the top is below the casing head, when the valve in the latter is turned to close the top opening, and the oil, which under former conditions would spray into the air and be lost, is now all caught in the flow tank. The slight opening in the rope notch of the valve to permit the torpedo line to slip through is not sufficient to permit an appreciable amount of waste.

The valve is maintained in this closed position until the shell is landed on bottom and the torpedo line withdrawn. It is then opened to permit the introduction of the squib, or other means employed to explode the shot, and is kept open until the well has cleaned itself, when it may be closed in time to catch the "second flow."

While usual practice demands that the well be open during shooting to permit the well to cleanse itself of the torpedo shells and of the sand and other material loosened by the shot, yet by the use of the control casing head all of this may be deflected into a tank without putting a back pressure on the well. Not only will all of the oil be saved, but a more complete record of the effect of

he shot will be found in the accumulations arising from fragments of rock broken off and thus trapped.

The introduction of the control casing head has made it possible to shoot wells of any size regardless of the amount of flow, and it has in practice demonstrated its value by checking the flow in a well which threatened to expel the shot, consisting of 20 quarts of nitro-glycerine contained in two shells joined together. In this case, of course, the valve was turned to close the bottom opening and entirely shut in the well. This was done instantly and without injury to the torpedo line.

Application of control head to gas wells.—While the name "casing head" would seem to imply a use limited to oil wells, the control casing head is equally useful in drilling gas wells, and is used in the same manner as in drilling wells for oil.

In many places it is customary to drill gas wells during daylight only and to allow the well to remain open during the night, thus wasting a large volume of gas and reducing the rock pressure on the gas that remains in the sand after the well is completed. With the control casing head on the well the gas can be shut in during the time when active drilling operations are suspended. Not only is the waste of gas stopped and a higher rock pressure insured, but also the fire hazard is practically eliminated.

When the well is completed the control casing head is utilized in the same manner as the common T fitting. The usual top and side connections are made to the head, with the advantage that in the event of leaky gate valves, or damage to the lines, the gas may be instantly shut in and repairs made without waste of gas or danger of fire.

After a gas well is completed, it is the usual custom to limit the flow of gas into a pipe line by partially closing the valve at the head of the well. This, in the case of a gate valve, leaves a crescent-shaped opening of great length and slight width, with the result that all of the gas in passing through is forced to rub the sides of the opening, causing rapid wear of the gate and seats and destruction of the valve. The control casing head, in contrast, gives a small round opening gradually increasing to an oval-shaped opening, thus presenting a minimum rubbing surface in contact with the gas and reducing the wearing action.

The tight closing of the valve in the control casing head and

the freedom from leakage are very important advantages in securing life and freedom from accidents.

Effect of sand on control casing head.—Owing to the absence of recesses and projections within the body of the control casing head, there is no place in which sand can lodge by flowing oil during drilling operations, therefore, has not in any way disturbed the easy operation of the valve.

While sand cannot lodge and interfere with the action of the valve, there is a possibility of injury from the cutting action of sand. To meet this condition the valve portion is made with a curved surface to deflect the flow gradually from vertical, in the casing, to horizontal, in the flow line. This curved surface is backed by a great thickness of tough metal which will for a long time resist the scouring action of the sand. By thus gradually changing the direction of flow, no flat surface is exposed to the direct impact of the sand and cutting action is materially reduced.

Some operators prefer to cushion the flow when the well is making much sand. This can readily be done by screwing a short joint of pipe into the top of the casing head and closing the top of the pipe by a metal plug. Sometimes a plug of wood is driven into the cushion pipe to protect the metal plug from being cut by the sand.

This cushion pipe may be assembled and secured in place, while the casing head is closed, after which the valve may be turned to the side position out of the path of the oil and sand.

The control head as an aid in killing a gas well.—Gas is frequently encountered in drilling for oil and interferes with the further drilling of the well. Experience has shown that gas may be found in large volume and at high pressure above a formation containing oil in paying quantities. This fact has led to enormous waste of gas in an endeavor to reduce the pressure so that drilling could be continued to the deeper-oil-bearing formation.

For a long time this waste of gas was considered necessary and was condoned on the ground that the value of the gas so wasted was less than that of the oil subsequently secured.

Aside from the loss due to the waste of the gas, the delay in drilling adds greatly to the expense of the well, and postpones the recovery of oil, entailing a further loss of oil through offset wells

which have previously tapped the oil sand and are drawing from the common pool.

It behooves the operator to complete his well in the shortest time possible; therefore, the modern method is to seal off the gas sand and continue drilling without further delay. The use of mud-laden fluid in killing a gas well is too well known to require a description here, but it may be interesting to know that the "lubricator" method of introducing mud into a gas well presented some practical difficulties in operation and was attended with some hazard.

The large gate valves which were used became difficult to operate, partly because they were not designed to operate in mud.

By using the control casing head already on the well, these difficulties and the expense of buying and the loss of time in securing special gate valves are avoided.

On top of the control casing head are set one or more joints of any size casing available (two joints of 10-inch casing are my own preference). To the top of the casing extension thus provided, a 2-inch pipe is connected and brought down the outside of the extension to within about 4 feet of the floor, the end being fitted with a valve or stop cock (Fig. 75).

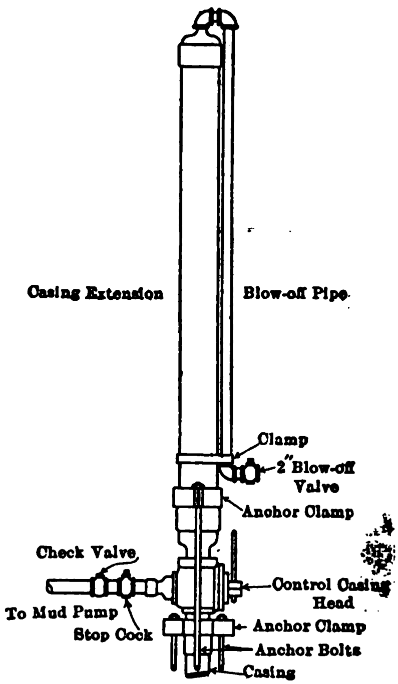


Fig. 75—"Lubricator" of improved form for introducing mud fluid into a well to "kill gas." All operations are controlled from the derrick floor without extra help being required

From the side outlet of the control casing head a 2- or 3-inch connection is made to the pump discharge. This line should be provided with a check valve and a stop cock.

All fittings should be of suitable strength, and as the control casing head is designed for a safe load of 1800 pounds per square inch all other fittings should be selected from extra heavy stock.

A. The Lakeview gusher flowing unchecked, 40,000 barrels a day

B. Fittings and connections of one of the gushers in the Midway District.

C. Connections of one of the gassers in the Buena Vista hills.

Photos Courtesy of United States Bureau of Mines.

Fig. 76

The 2-inch down pipe from the top of the extension should be securely clamped to the extension, and the valve-controlled outlet should be turned in a direction away from the operator.

These fittings are all made while the well is shut in. The pump is then started and mud-laden fluid pumped into the extension chamber until it is full, as indicated by mud showing at the outlet of the blow-off pipe. This outlet is then closed and the valve in the casing head opened permitting the mud to pass into the well. As soon as the extension chamber has emptied, the valve in the casing head is again closed and the outlet valve on the down pipe opened. This operation is repeated until the well is filled and the gas killed.

The advantage of this arrangement lies in the fact that everything is controlled from the derrick floor and no extra help is required. Also time is saved, since the pump will start delivering mud into the extension chamber as soon as the gas pressure is reduced, and, further, it is possible to pump directly into the well without any change of fittings.

The Mortenson Well Capper[1]

Description of apparatus.—The Mortenson well capper (Fig. 77 and 78) devised by A. C. Mortenson has been successfully used in the Midway and Coalinga fields for controlling oil wells of large flow after they have gone wild. It is a modification of the straightway gate valve, differing from the latter principally in the design of the hub, or barrel, which is made in two separate segments fastened together with bolts. The gate "b" is nearer the upper flange, thus dividing the orifice into two chambers of unequal lengths, the larger one "c" having two circular openings "d" 4½ to 6½ inches in diame-

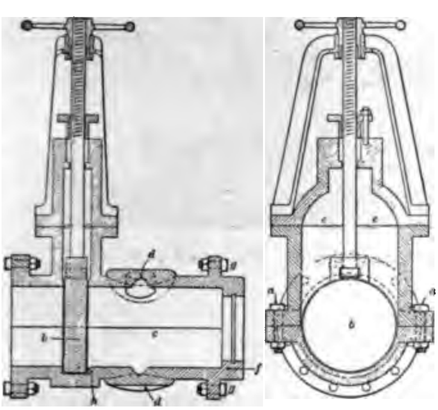


Fig. 77—Mortenson well capper

[1]Arnold and Garfias in United States Bureau of Mines Tech. Paper, No. 42.

ter. The recess "e" is designed to allow the gate to be drawn back of the clear about three-quarters of an inch, thus making possible the clamping of the capper around the well casing without danger of damaging the gate. The lower part of the apparatus has a grooved shoulder "f," provided with hydraulic packing in order to prevent the backward flow of oil or gas between the casing and the

A. View of 16 by 16 inch timber placed over a gusher to check its flow. The sand accompanying the oil soon bored the holes shown

B. Gusher controlled with a Mortenson Capper. Notice oil cushions
Fig. 78

capper, there being enough space between the shoulder and the side openings to allow for the standard casing collar. The capper and the casing are further secured by four anchor bolts, which pass through the lower flange at "g," into a bed of concrete around the casing, and to the upper flange are bolted screw flanges to fit different sized casings.

A detail in the design of the capper that at times plays a very important role in its successful operation is the rounding of the lower edge, "h," of the groove into which the gate fits; because of this provision, whatever sand may be forced into the groove when the gate is being closed is easily washed down, thus permitting the gate to be closed tight. The apparatus is manufactured in different sizes; that adaptable to 6¼-inch casing weighs about 1600 pounds, the 8¼-inch about 1600 pounds, and the one for a 15½-inch casing is estimated to weigh 3600 pounds.

Oil-cushion attachment.—In order that the sand usually accompanying the oil in the California fields may not wear out any metal cap placed on the T, an oil cushion (Fig. 78-B) is provided. This consist of a pipe about 8 feet long, having a tight hardwood plug and a cast-iron screw cap on the opposite end. This chamber is constantly full of eddying oil and sand, and thus affords a yielding cushion that effectively retards the velocity of the sand grains and minimizes their wearing action. The wooden plug affords added safety as it is not as quickly attacked by the sand as the unprotected metal cap. To the other opening of the T are connected the necessary fittings to divert the flow into as many channels as needed, and additional oil cushions may be provided if safety is required.

Mode of operation.—The peculiar design of the apparatus suggests at once its mode of operation. If the uppermost joint is sound and the top of the casing is accessible, the two segments of the capper are readily bolted together around the casing collar. This operation presents no difficulties, as at no time is the flow of oil disturbed in any way, which is the essential difference and advantage of this method compared with those which necessitate partly obstructing the flow of gas or oil before the apparatus is placed in position. The necessary nipples, gates, etc., are connected to the side openings to take proper care of the oil when the flow is diverted laterally by closing the gate on the capper. Once this is accomplished the connections on top of the capper are made without delay, as the side outlets are intended to take care of the flow only temporarily. The fittings generally used are an 18-inch nipple, directly over the capper, a two-way T, and whatever additional nipples, valves, etc., are needed to divert the flow as desired.

If the uppermost joint is damaged, a hole is dug around the cas-

ing and the apparatus is clamped to the first sound joint. As an added precaution, the excavation may be filled with concrete and the capper secured by means of the anchor bolts. After the side connections have been made the upper joint of casing is unscrewed and raised above the gate within the body of the capper to allow the closing of the gate, and thus divert the flow to the lateral openings.

When the top connections have been made, the gate of the capper is opened slowly to allow some of the oil to flow through the capper and test the upper connections, and if these are found safe the gate is entirely opened. The gate valves attached to the side connections can then be closed without trouble, thus placing the well under perfect control.

This method has been found effective in controlling oil wells on fire, since if it is possible to reach the casing one or two joints below the mouth of the well, the flow of oil can be diverted through the side openings and allowed to discharge at any safe distance away from the well. In this operation, after the upper joints have been unscrewed, it is best not to remove them from the capper, but to lift them just enough to allow the closing of the gate, the design of the apparatus permitting such operation. After the Pacific Crude gusher in the Midway field caught fire it was subdued by the method outlined.

Special Methods Used in California for Controlling Gas Wells[1]

The capping of gassers.—The method described below has been used successfully in the Buena Vista Hills (by J. A. Pollard) for capping some gassers at which no provision had been made for controlling the flow through the inner casing or between the casings. As the flow was mainly from the inner casing ,it was decided to eliminate the chance of the gas flowing between the casings after the inner casing had been closed by first placing the equivalent of a blow-out preventer apparatus on the outer casing. An operation of this sort embraces the following general features: A device (Fig. 79) with a special cast-iron four-way T, "a," with stuffing box, "b," heavy gate valves, "c," connecting nipples, "d," etc., is built up. This is raised about 10 feet over the casing head, and by means of the guy ropes is then lowered to the casing, over the

[1]Arnold and Garfias in United States Bureau of Mines Tech. Paper, No. 42.

stream of gas, and bolted to the casing head. The valves are then partly or entirely closed. The outer casing is next anchored down by means of the clamps, "e," embedded in concrete, the inner string being secured to the T with the clamp-and-bolt arrangement shown in the figure.

After provision had been made in the manner described to prevent possible flow between the casings, the operation proper of capping the gasser was carried on as follows:

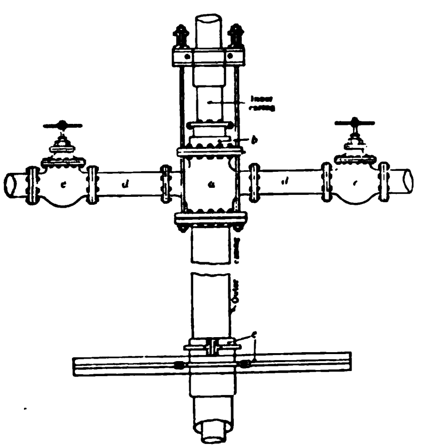


Fig. 79—Device for capping a gasser

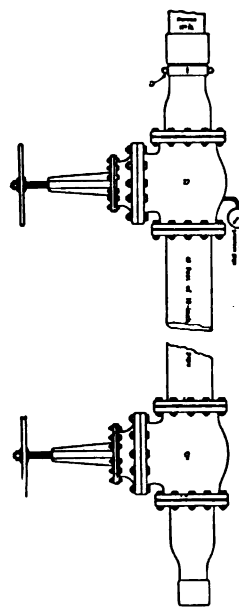


Fig. 80
Special apparatus for capping a gasser

Details of the method.—An apparatus (Fig. 80) was assembled that was made up of two special valves, "a," "b," weighing about 4700 pounds each and connected by about 40 feet of 40-pound 10-inch casing. Swage nipples reduced the diameter of the apparatus to that of the well casing. The lower valve was provided with a pressure gage, as shown in the figure. The apparatus was assembled on the ground, the valves being left open to insure free passage for the gas. A collar, "c," with four rings, was placed in its lower part, and to the rings were attached guy lines that passed through blocks generally made fast to the legs of the derrick

Under the collar on the upper end of the apparatus was clamped an elevator, and to this was attached a wire about 30 feet long, having its other end tied to the hook of the casing block or to any other suitable block-and-tackle arrangement. The hook was not attached directly to the elevators, as the great bulk of the block would obstruct the passage ot the stream of gas. The apparatus was raised about 10 feet above the casing head, where the stream of gas was less compact, and by means of the guy lines and blocks was then lowered to the casing and screwed in place. The flow of gas offered comparatively small hindrance to this operation, as the valves of the apparatus were wide open and the diameter of the apparatus was larger than that of the casing. Care had to be exercised in bracing the apparatus before releasing the wire line attached to the elevator, so that the vibration caused by the gas would not damage the connection to the well casing. After the apparatus had been screwed in place the valves were closed, thus controlling the flow. The upper valve was provided with a grooved wheel, around which was wound a wire for controlling its operation from the derrick floor.

Sealing or "killing" a gas stratum.—In case it is desired to "kill" the gas after the flow has been controlled in the manner just described, the following method can be employed: When the apparatus mentioned above has been put in place, as described, the lower valve is closed and the 40 feet of 10-inch casing is filled with mud-laden water by means of a pump fitted with valves that can work in water containing 40 per cent of solids. The upper valve is then closed and the lower one opened; the mud laden water then drops to the bottom of the well. The lower valve is again closed and the upper one opened, thus permitting the escape of the gas displaced by the mud fluid but preventing an increase in the pressure of the well. The operation is repeated until the weight of the column of fluid in the well is enough to overcome the gas pressure. Both valves are then opened, and the well is filled with fluid. The weight of the column of fluid forces the fluid into the gas stratum to be sealed.

If the pressure in the gas stratum exceeds that of the column of mud-laden fluid in the well it becomes necessary to attach to the head of the well a pump capable of furnishing as much additional pressure as is needed to overcome the gas pressure and the force the fluid into the gas-bearing stratum, thus sealing the stratum with

mud and excluding the gas from the bore. The pump pressure should be maintained for several hours and then an attempt made to force more fluid into the well. If no more fluid can be pumped in, work on the well can be resumed.

If the well is being drilled, great care should be taken not to make too much hole at one time, as it easily may be seen that by drilling fast the bit will soon enter the rock into which the mud has not entered, especially if the gas rock be so dense that the mud-laden fluid can not be forced much below the bottom of the hole. By forcing in mud and drilling slowly the gas can be excluded from the rock ahead of the bit, so that no gas will be encountered.

Great care should be taken in releasing the pump pressure from a well after the fluid has been forced in, because a sudden release of pressure may cause all of the fluid to be ejected, undo the work that has been done, and permit the well to blow gas again. If subsequently it becomes advisable to recover the gas or oil excluded, this can be accomplished by perforating the casing opposite the clay plastered beds and reducing the pressure inside the well or by bailing out the fluid mud.

Method Used in Closing the Potrero Del Llano Well[1]

The device for getting the great well under control was planned by F. Laurie and applied under the supervision of S. Weaver and F. Laurie. In this device a heavy clamp is placed immediately under the collar of the 8-inch casing, of which there are about 1700 feet in this well. To this clamp, on opposite sides of the casing, are fastened 2-inch rods, hinged near the lower ends. The upper ends of these rods pass through a clamp above an 8-inch T-joint having two gate valves. At the lower end of the T-joint is a swedged bell nipple, 8″ to 10″. By means of guys the T-joint on its hinged supporting rods was swung from a horizontal to a vertical position, bringing the bell nipple directly over the end of the 8-inch casing. The supporting rods are provided with threads and nuts at their upper ends, and by means of these nuts the bell nipple was forced down over the end of the casing. An 8-inch pipe was connected to the T and the upper valve was gradually closed, the oil being thus forced through the pipe into the reservoir. The first controlling device had been tested to only 800 pounds, for it was not con-

[1]Described by David T. Day in Mineral Resources, U. S. 1910.

sidered safe to close the well completely. A new T-joint, bell nipple, and valves, tested to 2000 pounds, were later substituted and the well was completely closed. That is its present condition, except for a small leakage about the valve gaskets. An earthen reservoir somewhat over 60 acres in extent was quickly and efficiently provided, but in 60 days this was filled with 3,000,000 barrels of oil, although the flow was checked as much as was deemed safe.

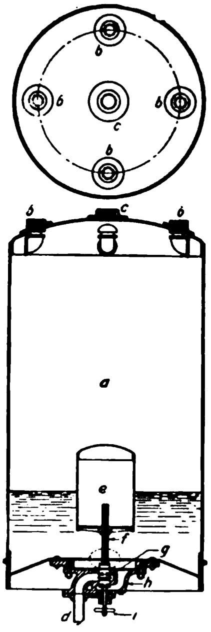


Fig. 81—Tico trap: a, tank; b, oil inlets; c, gas outlet; d, oil outlet; e, float; f, stem; g, float valve; h, valve body; i, valve stem handle. Gas trap patented

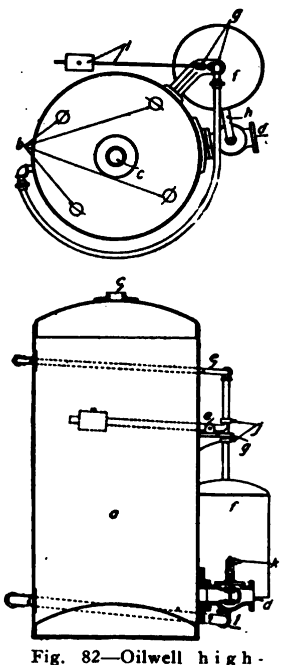


Fig. 82—Oilwell high-pressure trap: a, tank; b, oil inlets; c, gas outlet; d, oil outlet; e, equalizing pipe; f, float; g, guide; h, bracket from float to valve; i, lever and counterbalance; j, adjustment for travel of float; k, adjustment for travel of valve seat; l, feed to float.

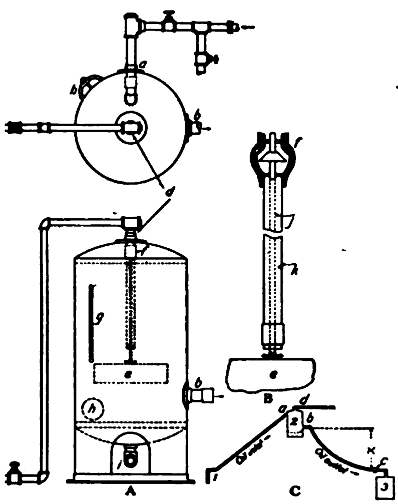
GAS TRAPS[1]

Upright cylindrical traps are often equipped with an outflow valve which operates mechanically and controls the amount of oil within the trap. Such traps are of two general forms, those actu-

[1]By W. R. Hamilton. Technical Paper No. 209, U. S. Bureau of Mines.

ed by an inside float (a), and those actuated by the weight of e oil.

The Oilwell low-pressure trap is one of the simpler forms of tomatic traps. Four openings are provided in the top for the let of the oil. The ball float controls the height of oil in the amber. This trap works satisfactorily on wells making clean ;ht oil and has been used with gas pressures ranging up to 50 unds per square inch.



'ig. 83.—Baker trap: a, oil inlet; b, oil utlet; c, check valve; d, gas outlet; e, rooden float, 6 by 12 by 24 inches; f, mergency check valve, 2 inches in diameter; g, gage glass; h, hand hole; i, clean-ut; j, valve stem supporting float; k, alve stem guide.

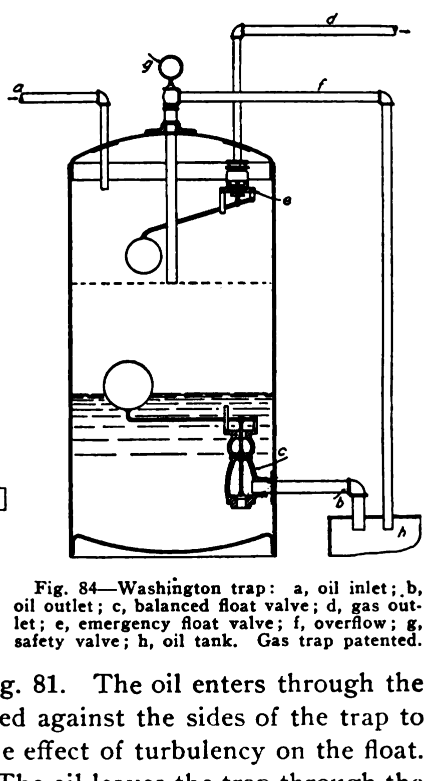


Fig. 84—Washington trap: a, oil inlet; b, oil outlet; c, balanced float valve; d, gas outlet; e, emergency float valve; f, overflow; g, safety valve; h, oil tank. Gas trap patented.

The Tico trap is shown in Fig. 81. The oil enters through the ur openings (b), and is deflected against the sides of the trap to parate the gas and to loosen the effect of turbulency on the float. ıe outlet for the gas is at (c). The oil leaves the trap through the lve (g), which the float (e) opens and closes. The float is of the en-bottom type, and is supported on an openwork spider on the em (f). The float will retain its shape under all pressures, as the ternal and external pressures are the same. This open construc-n cannot be used under a high vacuum, but the valve can be ed with any gauge pressure from zero to the pressure the shell built to stand.

The Oilwell high-pressure trap, shown in Fig. 82, is one of the traps most generally used. This trap works by gravity. An upper and a lower spring pipe "e" which enter, respectively, the top and bottom of the float, connect the outside float "f" with the interior of the tank "a." A guide "g" which keeps the float in proper position

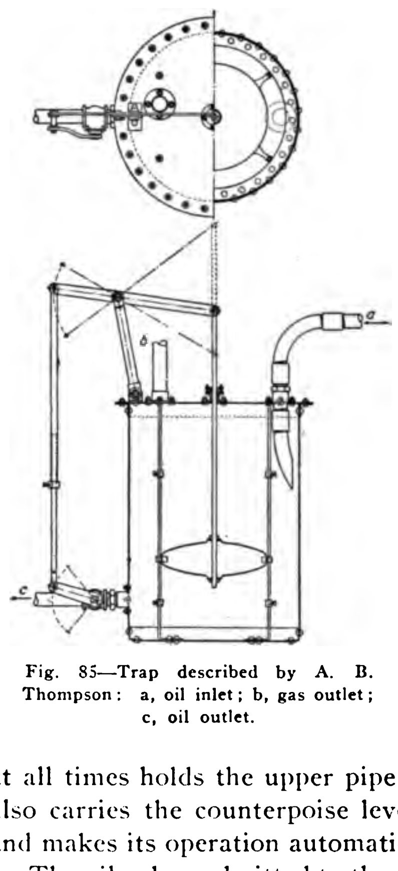


Fig. 85—Trap described by A. B. Thompson: a, oil inlet; b, gas outlet; c, oil outlet.

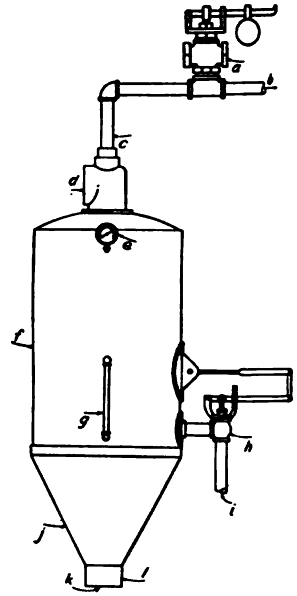


Fig. 86—Trumble trap: a, safety valve; b, gas outlet; c, extra strong pipe; d, oil inlet; e, pressure gage; f, expanding chamber; g, gage glass; h, balanced float valve; i, oil outlet; j, settling chamber; k, waste discharge for sand and water; l, nipple welded to tank.

at all times holds the upper pipe in place. This guide, or bracket, also carries the counterpoise lever that keeps the float in balance and makes its operation automatic. The trap acts as follows:

The oil, when admitted to the trap through the top openings "b," rises and part of it passes through the lower pipe "e" into the float "f." When enough oil has entered the float to overcome the weight of the counterpoise "i" the float lowers by gravity and opens the valve that is connected to its side with a bracket and lock nuts. The opening of the valve permits the oil to discharge through "d"

until lowered to a point where the counterpoise weight overcomes the weight of oil in the float. The float then rises to its original position, taking with it the valve, which is thus closed. This action is intermittent and is repeated so long as oil is permitted to enter the top of the trap. The trap is entirely automatic in is action, requiring no attention, except to see that the counterpoise weight and the valve stem are properly adjusted. The valve control is independent of pressure, and the device works equally well under vacuum or high pressure. The limit of pressures and capacities depends on the strength of material in the shell of the trap. This trap works satisfactorily with light oils, but would be less satisfactory with the more viscous oils, as the oil must flow rapidly through the spring pipe to operate the valve with reasonable promptness.

The Baker trap, shown in Fig. 83, is adatable for moderate pressure or a high vacuum. The oil enters the trap at "a" and is deflected downward. It flows unrestricted through the outflow pipe "b." The height "x" of the trap above the discharge end of the pipe "b" must be sufficient to overcome the loss of head due to a vacuum in the trap. To prevent the suction drawing air back through the oil discharge pipe, a horizontal check valve "c" is inserted in the line. Gas leaves the trap at "d." To prevent oil overflowing the trap and entering the gas line, in event of an unusual rush of oil the float "e" closes the valve "f" and pressure builds up in the trap, accelerating the escape of the oil. In the figure, A shows the trap in plan and elevation, B shows the detail of the check valve and float, and C the geenral arrangement of the trap and pipe connections for use under vacuum. In C, 1 represents the well, 2 the gas trap, and 3 the tank.

The Washington trap is shown in Fig. 84. This trap is designed for low pressures. The oil, which enters the trap at "a" is discharged at "b" through the balanced float valve "c." The gas is drawn off at "d." If an unusual rush of oil overtaxes the discharge line, the float valve "e" closes, and prevents the escape of oil into the gas line. Pressure then builds up within the trap and accelerates the discharge of oil. The safety valve prevents the pressure from rising excessively high, by permitting the oil to discharge through the pipe "f." This form of trap works well for moderate pressures and for oil free from sand particles.

In Fig. 85 is shown a trap illustrated and described by

Thompson.[1] In this trap the large inside float actuates a cock on the discharge line by means of the rocker above. This trap is suitable for low pressures and for wells producing light oil and no sand. A gate valve in place of the cock would be an improvement.

The Trumble trap, shown in Fig. 86, can be used either under a vacuum or under any pressure the material will stand. It has been used chiefly on flowing wells. It controls the flow of oil from the receiving chamber by means of a float operating through a stuffing box in connection with a balanced valve in the oil line.

The oil and gas are conducted downward through a smaller pipe inside the neck of the shell. The oil falls to the bottom and the gas, after passing up through the oil, rises through a series of baffles and enters the gas discharge line through a perforated pipe surrounding the oil and gas inlet line. The baffles thoroughly separate the gas and oil. At the request of the manufacturers, the details of construction of these baffles are not shown.

In this trap the sand and water are periodically drawn off at the bottom, the oil flows off at the side through an automatic discharge valve, and the gas, after passing through the oil, escapes at the top. This arrangement presents a satisfactory combination for a well that is not making large quantities of sand and thus does not need to have the sand pocket frequently emptied.

Horizontal tubular traps. — Two types of horizontal tubular traps are rather commonly used in California on gusher wells. Such traps can be quickly and easily made of material usually available about oil wells, and are convenient to instll, especially in an emergency. However, as a large proportion of the cost of installation is labor, which has no salvage value, they are used only on large flowing wells.

The Starke[2] trap, shown in Fig. 87, is made from pipe and fittings used in the oil fields, and can be assembled by the field force. As this trap has no large diameters or flat or conical surfaces, it is particularly adapted to high pressures. It is made of six to eight joints of pipe of relatively large size. At intervals of about four feet, 1-inch risers are tapped into the top of the large pipe. These risers are shaped like an inverted U bend and are connected with the top of a

[1]Thompson, A. B., Oil field development, 1916, 570-71.
[2]News items, Conservation of oil and gas in California, California Derrick, Vol. 7, Sept. 10, 1914, pp. 7-8. Burrell, G. A., Seibert, F. M., and Oberfell, G. G., The condensation of gasoline from natural gas: Bull. 88, Bureau of Mines. 1915, p. 99.

second horizontal pipe several sizes smaller, 8 to 10 inches in diameter, and each riser is fitted with a valve or stopcock. This second horizontal pipe is again connected at one end to a larger pipe also lying level, that acts as a reservoir or receiver, and gives off the gas through a riser of suitable size.

The oil or gas flowing together enter the large pipe or separating chamber through the flow line from the well. The first joint of the large pipe is not tapped with risers, acting more strictly as a separating chamber. As the mixture of oil and gas enters this pipe, the oil settles to the bottom and the gas is carried along the top and out

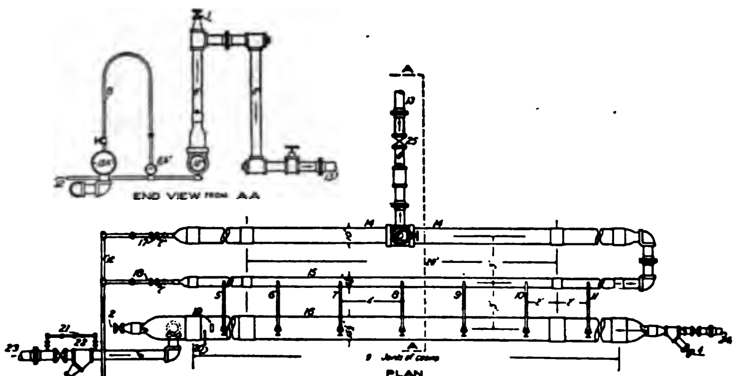


Fig. 87.—Starke trap: 1, 2, 3, 4, 4-inch gate valves; 5 to 11 1-inch risers; 12, 2-inch blow-off; 13, outlet to gas main; 14, 10-inch casing; 15, 6¼-inch casing; 16, 15½-inch casing; 17, 18, 2-inch gate valves; 19, pressure gage; 20, gage glass; 21, stopcock to regulate oil flow; 22, 1-inch by-pass; 23, oil outlet; 24, oil inlet; 25, 6-inch gate valve. Gas trap patented.

through the risers to the second horizontal pipe. Enough of these risers are used so that their aggregate cross section considerably exceeds the area of the flow line from the well. The oil and the gas separate and become quiet, thus there is no tendency to carry oil over with the gas through the risers from an effect similar to "priming" in a boiler. The oil that collects in the bottom of the large pipe is run off through a stopcock at the end opposite the one through which it enters. The level of the oil in this pipe is indicated by a gage glass and, even when a well is flowing large quantities of oil, remains quiet with only a slight pulsating effect, showing that agitation of the oil and gas has ceased. The stopcock is set to deliver approximately the same quantity of oil that the well is producing.

A pocket for collecting sand can be inserted in the trap, preferably near the point where the oil is taken off, and can be so arranged that the sand may be removed at convenience or when the pocket is filled.

In installing the Starke trap on wells equipped with reducing nipples the more recent practice is to do away with the nipple at the mouth of the well, so that the full backed-up pressure of the well is on the trap, and have the flow nipple, with its restricted opening, beyond the trap. Under these conditions the oil and gas

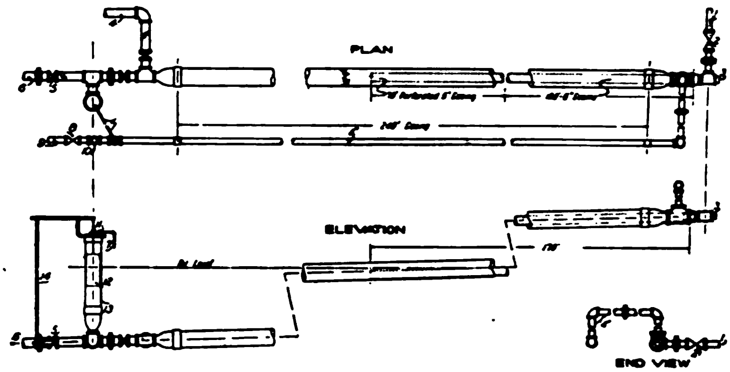


Fig. 88.—Bell trap: 1, 4-inch inlet from well; 2, 4-inch gate valve, extra heavy; 3, 4-inch plug; 4, by-pass to sump; 5, 6-inch butterfly valve; 6, oil outlet to tank; 7, 1-inch equalizer; 8, 4-inch pressure valve; 9, outlet to gas main; 10, safety valve; 11, stuffing box; 12, float, 10 inches in diameter and 24 inches long; 13, 12½-inch casing; 14, ¼ by 2-inch bar.

can be separated under pressure as high as 500 pounds, or as high as may be desired, as the control is on the discharge side of the trap away from the well, and there is no throttling between the well and the trap.

The pressure under which the Starke trap can be used is only limited by the bursting strength of the largest size of pipe, and by the strength of the fittings used. As 15½-inch screw pipe that will stand a pressure of 800 to 1,000 pounds per square inch and fittings tested to 1,500 pounds are commonly on hand, the limit of pressure on the trap is determined by the well rather than by the strength of the trap. In wells of the gusher variety as originally brought in both in the Midway and the Coyote Hills districts of southern California, 400 or 500 pound pressure upon the well was frequently necessary. By placing the trap in direct connection with the well, that

s, without any intervening pressure-controlling valve, a gas free of oil particles or unabsorbed gasoline is delivered at the backed-up well pressure and is therefore ready to be introduced without compression into a high-pressure transportation system.

This trap has no automatic control, but as it is only used on wells of unusually large production a man should be in constant attendance.

In the Bell trap, which is shown in Fig. 88, the mixture of oil and gas from the well enters the trap proper through a flow nipple for restricting the free flow from the well. Through this nipple the oil and gas pass into a 6-inch pipe, about 175 feet long, of which the end is perforated for about 70 feet. Six-inch perforated pipe, the same as that used on California wells, is used for this purpose. This 6-inch pipe is within a pipe of larger size, about 12½ inches in diameter and 240 feet long, and the two are connected by means of a 4 by 6 inch heavy steel bushing and swage nipple. A tee with a suitable size outlet is connected in the outer line at the oil inlet end to carry off the gas.

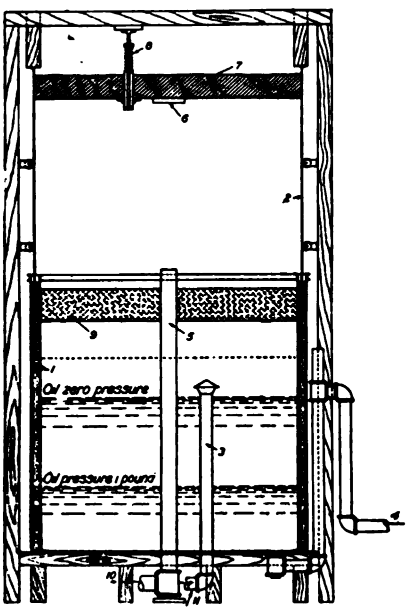


Fig. 89.—Scharpenberg trap: 1, annular tank; 2, cylindrical tank; 3, standpipe for entering oil; 4, oil outlet; 5, gas outlet pipe; 6, plate; 7, top of cylindrical tank; 8, relief valve; 9, excelsior screen; 10, gas outlet; 11, oil inlet. Gas trap patented

The 12½-inch pipe is laid on a gradient ranging from not less than 3 per cent to as much as 8 or 10 per cent, with the inlet end highest. At the lower end of the 12½-inch pipe is a 6-inch swage nipple, to which a riser enlarged to 12 inches is connected. In this riser is a wooden float, connected through a rod and stuffing box to a butterfly valve, which controls the flow of oil from the trap, thus making it automatic. The float is so situated as to maintain the oil level in the inclined pipe at such a height that the end of the perforated 6-inch

pipe, within the 12½-inch pipe, is submerged about 20 feet of its length.

The mixture of oil and gas enters the 12½-inch pipe or receiving chamber through the flow nipple and 6-inch pipe. A large part of the gas and some of the oil leave the 6-inch pipe through the perforations; the balance passes out at the end. The oil settles in the

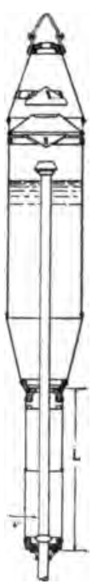


Fig. 90-A

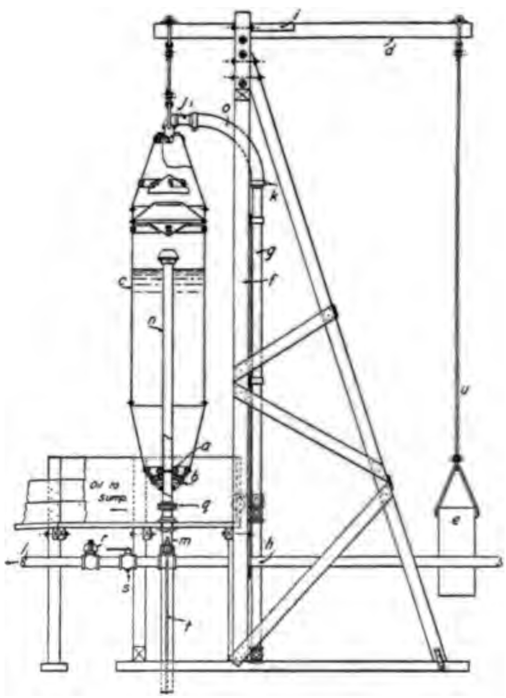


Fig. 90.—McLaughlin low-pressure trap: a, valve; b, valve seat; c, trap shell; d, beam; e, counterweight, made of old casing filled with scrap iron; f, support; g, pipe from gas line; h, oil line from well; i, iron guide for beam; j, gas outlet; k, hose clamp; l, discharge to sump; m, nipple; n, oil inlet; o, hose; q, flanger union; r, safety valve; s, emergency stop valve; t, hold-down rods; u, old ½-inch sand line; v, vacuum attachment; L, length of attachment. Gas trap patented.

12-inch pipe. The float and butterfly valve control its level and regulate its flow. As the gas rises through and above the oil, its direction of flow is reversed and it passes out at the intake end of the 12½-inch pipe through the side opening of the tee mentioned.

The Bell trap has been used on wells producing several thousand barrels of oil and many million cubic feet of gas a day. The butter-

fly valve does not shut off the flow entirely, as there is enough clearance around the valve to prevent any danger of its sticking from sand that may lodge about it. As a consequence this trap has satisfactorily handled oils that carry much sand in suspension.

Scharpenberg trap.—The Scharpenberg trap (Fig. 89) is an ingenious use of the principle employed in the construction of gas holders. The trap holds a constant pressure on the well and on the gas line. The annular tank 1 has two shells that form a water seal between them. A second circular tank 2 moves vertically between the two shells 1. A deflector in the oil-inlet pipe 3 throws the oil downward. The oil outlet 4 is through an oil seal, the upper end of which is open to the atmosphere to prevent syphoning. The gas-outlet pipe 5 is in the center of the tank 1 and extends slightly higher than the top of the tank. A layer of excelsior 9, supported upon wire screens, separates any fine particles of oil which might be carried in suspension by the gas.

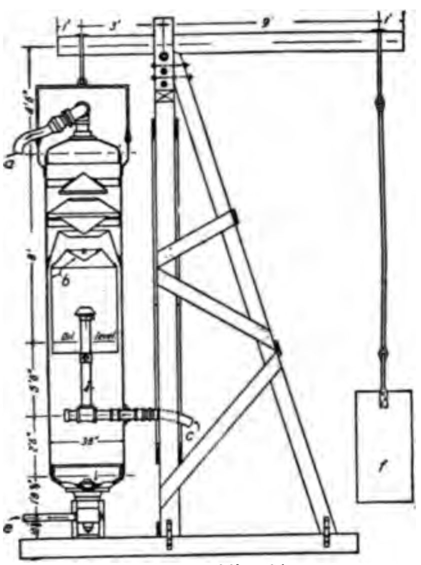


Fig. 91.—McLaughlin high-pressure trap: a, gas outlet, made of 4-inch hose; b, baffles; c, oil and gas inlet, 4-inch hose; e, oil outlet, 3-inch pipe; f, counterweight, equal to weight of empty trap, is filled with old iron. Gas trap patented.

When gas is being taken from the trap faster than it is produced by the wells, plate 6 seats itself upon top of pipe 5, closes it, and prevents a vacuum in the trap which might draw air through the oil and water seals. When gas is produced faster than it is taken away, the relief valve 8 prevents the blowing out of the oil and water seals when the floating tank has reached its upper limit of travel. This trap has been built about ten feet in diameter and the tanks about ten feet in height, and is best adapted for pressures of from one ounce to one pound per square inch. Besides the advantage of maintaining a constant pressure on the well and gas delivery line, the trap can be used conveniently for measuring gas.

McLaughlin Low Pressure Trap.—The McLaughlin[1] low pressure trap, shown in Fig. 90, is a cylinderical shell, supported by a framework or by springs in such a way that the weight of the shell is balanced. The automatic action depends upon the movement up and down of the entire shell and its contents. The inlet pipe enters the bottom of the trap and is stationary; to this pipe is attached the annular ring, forming the discharge valve. The line for carrying off the dry gas is connected to the top of the shell, preferably by a flexible connection, to permit free vertical movement of the trap.

At the bottom of the shell is an annular valve which is opened and closed by the vertical movement of the shell. The oil, gas and sand enter the trap through the line "h" from the well. On this line is fitted a cast-iron valve "a." This valve engages a cast-iron seat "b," which forms a part of the trap shell "c." The inlet pipe and the valve "a" are stationary, but the trap shell "c" and the valve seat "b" move up and down to close and open the valve. The trap shell "c" is suspended on one end of the beam "d," and the counterweight "e" is suspended from the opposite end of the beam. After the length of the beam arms have been established, the weight of counterbalance needed is found by trial. The oil, gas, and sand flow into the trap through the vertical pipe "n" and are deflected downward by the deflector on the upper end of this pipe. While this trap is empty, or the counterweight is heavier than the contents of the trap, the counterweight keeps the valve seat "b" on the valve "a." As soon as enough oil and sand, if sand is present, has been admitted to the trap to overbalance the counterweight, the shell moves downward. This opens the valve and allows the oil and sand to discharge into the wooden trough until the counterweight again overbalances the weight of the shell and its contents and closes the valve. The position of the entire unit may be so maintained that the oil will flow constantly and almost uniformly from the trap, and the discharge valve will open only enough to allow the passage through it of the amount of oil produced.

The gas separates from the oil in the shell, rises through baffles, and passes out from the trap through the top connection into the

[1]For descriptions of McLaughlin trap, see Paine, P. M., and Stroud, B. K., Oil production methods, 1913, pp. 171-172; Oil Age, Saving the gas, Vol. 9, Mar. 27, 1914, pp. 5-6; Beckley, R. E., Theory of action of McLaughlin automatic gas trap, Bessemer Monthly, October, 1914; Dykema, W. P., The recovery of natural gas by refrigeration and compression, Bull. 151, Bureau of Mines, 1918, p. 23.

pipe line. As the oil flows from the trap quietly and without the churning that takes place when oil highly charged with gas flows freely from a well, much of the lighter constituents or vapors is held in the oil that would otherwise be lost.

The action of the trap is positive, as the operation of the valve that controls the flow depends upon the weight of a considerable quantity of oil. This valve is placed at the bottom of the receiving cylinder and allows any sand or water coming from the well to pass out with the oil. The oil after leaving the trap is passed through boxes to collect the sand, which is drawn off or shoveled away as it accumulates. Any water present is drawn off from the storage tank. The McLaughlin trap can handle large quantities of sand. The valves are the only parts that are worn by the sand and are easily replaced.

When this trap is placed under vacuum, the attachment shown in Fig. 90-A is added. The length, L, of this attachment depends upon the vacuum, measured in inches of mercury, that is to be maintained on the trap.

Fig. 91 shows the McLaughlin high pressure trap. The action is the same as that of the low pressure type except that the oil enters at the side of the trap through a hose. This discharge valve does not connect with the inlet pipe, but opens when the trap descends; the valve stem protrudes below the trap and comes in contact with a seat provided for the purpose. The oil discharges into a pipe line when the well makes no sand. In the latest installations the beam and counterbalance are done away with; springs support the trap. The tension of the springs is adjusted so that the oil is kept at the proper height in the trap.

Gas Trap Used In Mid-Continent

The Smith Separator as sold by Chestnut and Smith and as illustrated in Fig. 92, is sold complete ready to be connected. Two or three men can easily connect one up in two days' time. A 5x16-foot separator will take care of a well making as high as 5000 to 6000 barrels of oil and 10,000,000 to 15,000,000 cubic feet of gas per day, a perfect separation of oil and gas being made. They are designed to withstand a hydrostatic pressure of 80 pounds per square inch. The regulators on this tank regulate absolutely the level of

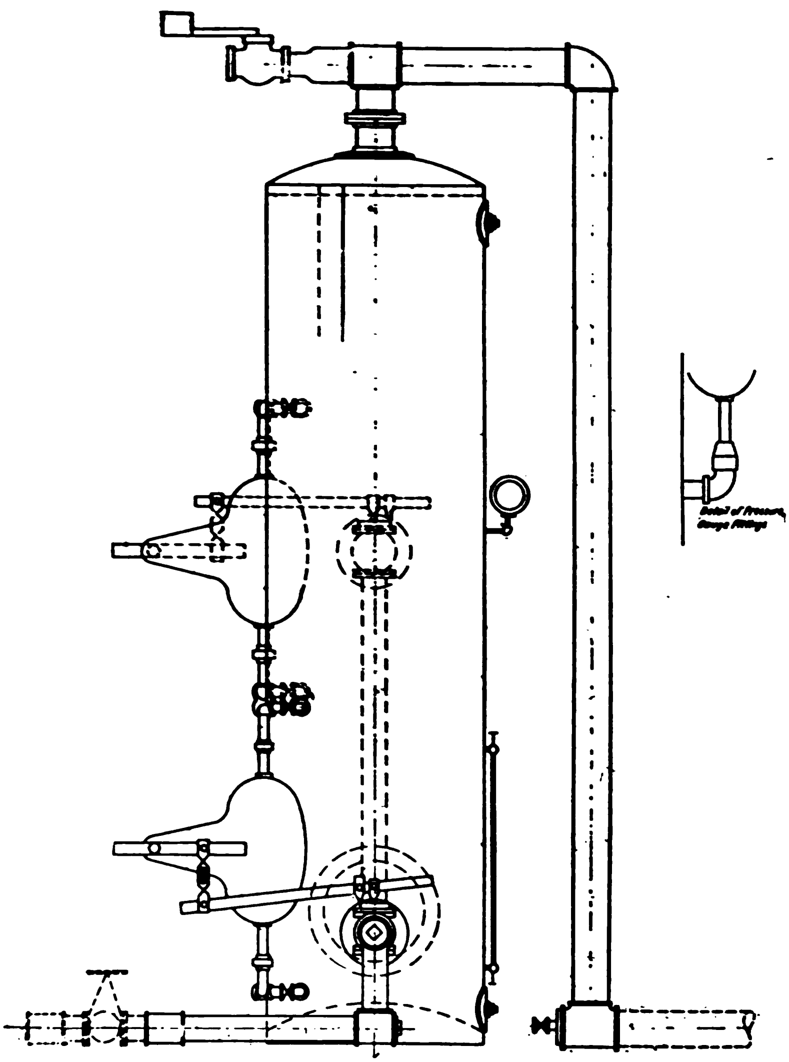


Fig. 92.—The Smith Separator.

For separating oil and gas from flowing wells. **A separator as illustrated will handle 50** to 6000 barrels of oil per day and 10,000,000 to 15,000,00 **cubic feet of gas. This type** separator complies with Rule No. 21 of the Texas **Railroad Commission relative to t** conservation of oil and gas.

the oil in the separator no matter whether the well is flowing by heads or steadily. When the fluid reaches this certain level the regulator opens a valve and the gas pressure forces the oil to the storage tanks.

SWABBING

In some fields the crude produced is heavily laden with hydrocarbons and precipitates paraffine wax to the extent that it is not economical to pump the wells. In some cases it is impossible to pump them successfully. The deposition of parrafine is so rapid that it would be necessary to constantly clean the wells and pump equipment. Under these conditions the wells are swabbed.

The swabs are of the proper diameter to fit the casing used and are run in the hole on a steel line. The packing consists of one or more rubber rings which can be replaced when worn. They are fitted with a ball valve to permit being lowered into the fluid. The swab is usually run with a sinker bar, the string of tools then consisting of the wire line socket, the sinker bar and the swab.

A good mechanical plant for swabbing consists of one or two 14¼x19-inch steam engines directly connected to a hoist. The drum is fitted with a signal device which designates the location of the swab in the hole while being lowered or pulled. A bell is rung when the swab nears the top of the hole. Since the swab can be and usually is pulled at the rate of 2000 feet per minute this device is necessary as well as the high powered brakes which are attached to the drum. Obviously the danger is in running the swab through the crown block or in losing the swab in the hole and overwinding the wire line. The mechanical problems connected with swabbing are essentially those of hoisting.

The question of submersion is one to be decided by trial as each well will develop individual charactertistics which can not be foreseen. The same applies to the number of runs necessary to obtain the maximum production.

Swabbing plants are not mechanically efficient and will not ordinarily run over 20 per cent but in the Galician fields where the swabbing process has been developed and to which fields its use for the purpose of production is practically confined, wells 3000 to 4000 feet in depth and standing from 200 to 300 feet in fluid have been profitable on a production of 25 to 50 barrels.

Wells in other fields are often swabbed for the purpose of agitation and where this is the case no other equipment than that used in drilling the well is necessary, excepting the swab and a supply of extra rubbers. The swab is commonly run in the hole on the drilling line from the bull wheels using only rope socket and jars above. However, it is sometimes run from the sand line either with or without a sinker bar.

In the Burkburnett field of North Texas swabbing has been developed to a fine art and is probably in continuous use on more wells there than in any other field in the United States. It has been found that more production could be recovered in this manner than by using any other method. The standard charge for swabbing made by the companies who make a specialty of this business and who furnishes their own equipment is one hundred fifty dollars per day. (1919).

THE AIR LIFT FOR PUMPING OIL WELLS

By JOSEPH A. TENNANT

It is believed that the first application of compressed air to oil well pumping was made in the Baku oil fields of Russia in 1899. These early experiments were carried out under unfavorable conditions, but nevertheless were effective enough to increase the yield of the first well tested from 60 barrels to 300 barrels per day, while the daily fuel consumption did not exceed 11.5 barrels of oil. The result of these experiments was so satisfactory that the great Baku oil fields have since been almost entirely pumped by compressed air. When the Texas and Louisiana Coastal pools were opened up two years or so later, the method of pumping oil wells by compressed air was introduced immediately. Large air compressor plants were installed at Evangeline and Humble and many millions of barrels of oil were produced by the air lift, which thereupon became one of the principal production-increasing factors in the oil industry.

Accumulation of data regarding the most efficient piping methods, pumping pressure, and limiting well capacities have at this date about standardized the air lift system of pumping, and have enabled the manufacturers to produce a highly standardized line of equipment to meet the needs of the field for this service. The limitations and advantages of the air lift system of pumping have become well defined by time and usage, the mystery which formerly

enshrouded its operation has been largely dissipated, and its use and application now are based on a combination of the best engineering skill with long practical experience.

Air lift—Theory and calculation.—The depth at which the fluid in a well stands below the level of the ground depends upon two factors, the weight of the column of fluid in the well, and the pressure of the fluid (and gas) in the sand at the bottom of the well tending to overcome this weight. If the pressure of the fluid (or gas) is sufficient to overcome the weight of the column of fluid in the well, the well will flow. If the pressure is insufficient to cause the well to flow, a flow may be induced either by increasing the pressure in the sand, or decreasing the weight of the column of the fluid in the well. This latter action is exactly that of the air lift, under which system air is admitted to and intimately mixed with the column of fluid in the well, and, this mixture of air and fluid being lighter than the column of fluid alone enables the pressure of fluid in the well to discharge the mixture of air and fluid above the surface of the ground.

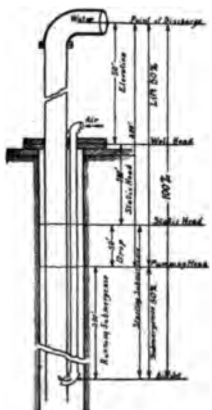


Fig. 93
Action of Airlift

The action ofthe air lift is shown diagramatically in Fig. 93 to which the following definitions apply.

Static head is the distance from the surface of the ground to the standing fluid level in the well, when not being pumped.

Drop is the distance the fluid recedes when the well is delivering a definite quantity of fluid.

Lift consists of **Static Head** plus the **Drop**.

Submergence is the depth that the air pipe is submerged below the pumping level of the fluid in the well. Starting submergence, which is temporary, affects only the starting air pressure, which the running submergence bears directly on the output and efficiency of the air lift installation. Submergence is usually expressed as a percentage of the total length of fluid column from the point where the air is introduced to the point of discharge. Thus fifty per cent submergence means that the total lift and the submergence are equal. The necessary percentage submergence varies with the lift. As the lift increases the necessary submergence decreases.

In **water well pumping** the following will give in a general way the range of most efficient submergences.

For a lift of 20 feet, 65 per cent.

For a lift of 750 feet, 35 per cent.

Actual submergence in feet in the above cases would be 37 feet for the 20-foot lift and 404 feet for the 750-foot lift.

The data collected in the **oil fields** applies only to local conditions and the results at first hand appear dissimilar to the general statement above regarding lift and submergence. This can be accounted for in most instances by the presence in oil wells of varying volumes of gas under considerable pressure, while the varying densities of the oil and water mixtures must, also, be recognized as modifying any general rule.

The gas accompanying the oil considerably modifies the action of an air lift, both by diminishing the theoretical air pressure required and by assisting in the aeration. If a packer is set in the well in order to compel all the gas to pass with the oil up the discharge line, the amount of air required to sustain a given discharge will often be reduced.

Compressor capacity.—For pumping water wells with lifts up to 500 feet, to calculate the volume of air required, the following formula, which is partly due to Mr. Edward A. Rix, A. S. E., is used.

$$VA = 0.8 \frac{h}{C \log \frac{H + 34}{34}}$$

VA equals actual delivered air required per gallon of water (actual delivered air equals compressor piston displacement at rated speed times volumetric efficiency).

h—Total lift in feet.

H—Running submergence in feet.

C—Constant as given in table.

Following table shows the value of "C" for different lifts as used by the Air Lift Engineering Department of the Ingersoll-Rand Company.

Lift in feet (h)	Constant
10 feet to 60 feet inclusive	245
61 feet to 200 feet inclusive	233
201 feet to 200 feet inclusive	216
501 feet to 650 feet inclusive	185
651 feet to 750 feet inclusive	156

For **oil well pumping** so many variable factors enter that it is usually useless to attempt to apply the above formula. Test data must be kept of the air lift pumping installations in each field and a careful engineering study made of them to determine the proper compressor pressure and capacities for that individual field.

In the **Kern River** Field in California, a typical installation requires 1.5 cubic feet of free air per gallon of fluid delivered.

In **West Columbia** field in Texas, one producing company with ten wells operated by the air lift system is requiring but 1.0 cubic feet of free air per gallon of fluid delivered.

Since in the production of oil it is necessary always to secure the utmost possible **output** from each well, air lift installations are usually made with a view of taking from the well all of the fluid that it can safely deliver per twenty-four-hour period. Since the well casing in any one particular field is in usual practice limited to two or three sizes, each having a fairly definite fluid capacity, it is customary to limit air compressor sizes to one or at most two, in order to simplify machinery installations, and to enable the operator to use standardized air compressor units.

Calculation of pressure—For water pumping the following calculation determines the starting and working air pressure.

Starting pressure equals depth of air line in well less the static head x 0.434.

Working pressure equals depth of air line in well less the pumping head x 0.434, plus pounds friction head lost in air pipes.

The factor of 0.434 used above is the pressure in pounds per square inch exerted by a column of water one foot high. With an oil and water mixture, this factor should be multiplied by the specific gravity of the mixture.

Field of application in oil production.—Where sufficient submergence is available, the air lift can be applied to any well, but its application is in practice usually limited to the following cases:

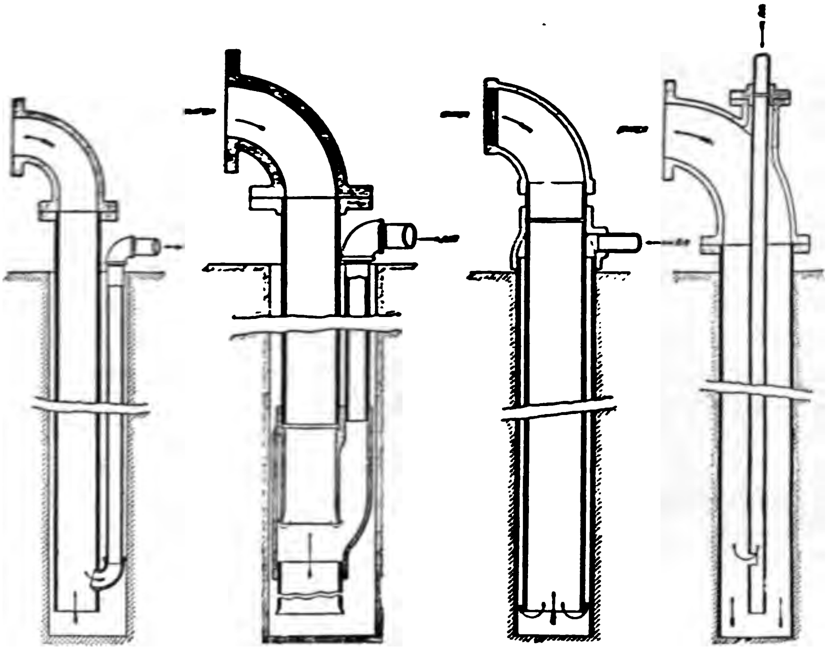
(a) Where the oil capacity of the well is greater than can be handled by the standard rig pump.

(b) Where water is mixed with the oil to such an extent that very large quantities of fluid must be handled to secure a profitable yield of oil.

(c) Where an underground migration of water towards a

certain well or set of wells can be established, so that practically all of the water in the field can be handled through these wells by means of the air lift, leaving the other wells to handle pure oil.

Methods of piping.—Figure 94 shows four of the usual methods of piping wells for air lift pumping.



a b c d

Fig. 94.—Methods of piping wells

Figure 94-a shows the original Pohle lift in which the air and water pipes are placed along side of each other, the air pipe being led into the water pipe at the bottom of the well. This system is now in disuse, having been largely succeeded for water wells by the system illustrated in Fig. 94-b, which differs from the above only in the use of an anular foot piece for connecting the air and water pipe at the point of air entry.

Figure 94-c shows a method which is used both for water and oil wells and is known as the **Saunders System.** Air is admitted between the well casing and the discharge tube, being confined by a tight casing head at the top of the well. The fluid is discharged

hrough the central tube. This system has the advantage of utiliz-ng all the gas pressure available in the well.

Figure 94-d shows the **central air pipe system** which is used to btain the greatest possible output for a given size of well casing. The air pipe is suspended directly inside the casing. The air asses down the central pipe, the fluid and air discharging between he air pipe and well casing.

The central air pipe system is in universal use in the oil fields ut caution should be observed in using this system, since if sand n any considerable quantity is present in the well, the cutting ac-ion of same at the high velocity of discharge will quickly ruin the asing. It is often advisable, therefore, in oil field practice to sus-end a discharge pipe in the well and to suspend the air line inside he discharge pipe. This gives a central pipe system with the dis-harge between the air line and the discharge pipe and is, there-ore, without erosive action on the casing.

It has not so far been found advisable to use any of the so-called atented foot pieces in the pumping of oil wells where the lift is ery high.

OPERATION DATA

General practice as regards the piping of oil wells for pumping y compressed air consists almost entirely of the cut and try nethod, and is based on data obtained from other wells being umped by air in the same field.

In the **West Columbia** fields, Texas, the usual central pipe in-tallation consist of 1600 feet to 2400 feet of 2-inch tubing inside of 6-inch casing. Where the amount of fluid which can be obtained rom the well is limited in quantity, a 3-inch air line inside of the -inch casing gives better results and a more uniform rate of dis-harge. The static head in this field averages 400 feet and the perating pressures are between 300 and 400 pounds, per square nch at the casing head. To show the wide range of variation in ven as small a field as West Columbia, in one well there was 2450 eet of 2-inch air line inside of a 6-inch casing and this well was ischarging 10,000 barrels of fluid daily, of which about 10 per ent was oil, at an operating pressure of 450 pounds, per square nch. As stated above, in this field approximately one cubic foot f free air was required per gallon of fluid delivered per minute.

In the **Kern River** fields in California, it was customary to use

600 to 800 feet of 1¼ to 1½-inch air line inside of a 2½ or 3-inch discharge line, or casing. The most satisfactory submergence in this field for economical operation was found to be between 30 and 40 per cent, and the wells were operated at pressures varying from 150 to 200 pounds per square inch at casing head.

In the **Evangeline** fields in Louisiana, it was customary to use a 1¼ to 2-inch air line inside of a 4-inch discharge casing, and usually from 900 to 1500 feet of air line was placed in the wells averaging from 1700 to 2000 feet in depth.

In the **Blackwell field** in Kay County, Oklahoma, a large air lift pumping installation was installed under the writer's supervision, and the following data taken from the first four wells piped for the air is given.

Static Head 975 feet. **Jones No. 2**

2100 feet 2-inch air line inside 5 3/16-inch casing (Central pipe system).

Starting pressure, 550 pounds per square inch. Running pressure, 375 pounds per square inch.

Static Head 1000 feet. **Wolf No. 1**

1750 feet, 3-inch flow line inside of 6-inch casing. Air on casing (Saunders System).

Starting pressure, 550 pounds per square inch. Running pressure 310 pounds per square inch.

Static Head 1100 feet. **Duluth No. 2**

2200 feet of 2-inch air line inside 5 3/16-inch casing.

2200 feet of 2-inch air line inside 5 3/16-inch casing. (Central pipe system.)

Starting pressure, 475 pounds per square inch. Running pressure, 290 pounds per square inch.

Static Head 700 feet. **Wolf No. 2**

1500 feet of 2-inch air line inside of 5 3/16-inch casing. (Central pipe system.)

Starting pressure 280 lbs. per square inch. Running pressure 190 lbs. per square inch.

Following actual piping data on a typical Humble, Texas, well will be of interest:

Well No. 9	Paraffine Lease
Depth casing	2593 feet.
Size casing	6 feet.
Depth screen (4¾")	100 feet.
Size of air line	3 inches tubing.
Depth of air line	1300 feet.
Starting pressure (air)	468 lbs. per sq. inch.
Running pressure	330 lbs. per sq. inch.
Static Head	400 feet.
Starting submergence	900 feet.
Running submergence	621 feet.
Pumping head	669 feet.
Submergence	47.7%
Fluid delivery	85 gals. per minute.
Steam pressure	125 lbs. square inch.

The air compressor plant.—Early practice dictated **steam driven compressors.** with attendant boiler stations. Oil was worth $1.00 per barrel, or less. Oil field boilers were plentiful and inexpensive and the need of present day efficiencies in oil production was not at that time realized. The steam driven units were fairly portable and due to their wide variation of speed with consequent variation in delivered air capacity, proved very flexible units in a field of application, which was in itself in the experimental stage; and, therefore, likely to avail itself of all the flexibility possible.

Compressor sizes.—Machines installed in the Gulf Coastal fields in the early days were approximately 500 cu. ft., 750 cu. ft. or 1000 cu. ft. per minute capacity, and designed for pressures ranging from 500 to 1000 lbs. per square inch. Modern practice with Coastal pools dictates but two sizes of machines: viz., the 500 foot, 500 pound machine and 300 foot, 500 pound machine. Accessibility and ease of repair dictate the cross compound duplex type of machine (with each cylinder easily and completely accessible for repairs and replacement) although a few straight line compound machines are still running in some of the older plants. Typical machines of the duplex type are those built by the Ingersoll-Rand Company, who make the two following sizes, which have come to be standard for oil field work.

(a) 12x15 and 6¾x16", piston displacement 487 cu. ft. per minute, final air pressure 500 lbs. per square inch.

(b) 10x12 and 5½x14", piston displacement 308 cu. ft. per minute, final air pressure 500 lbs. per square inch.

In at least one of the more modern types of air compressor plants, which was installed at Goose Creek under the writer's direction, **compound steam cylinders** were substituted for the duplex steam cylinders with which these compressors are usually equipped. With this additional refinement a saving of from 15% to 20% of the fuel cost was effected.

An air compressor power plant installation is subject to improvement in economy at the hands of the trained mechanical engineer just as is any other type of power plant. Installation of proper oil burning equipment, installation of a properly selected boiler feed water heater, the installation of heat insulating covering for boilers and piping, the installation of separate compressors for blowing low lift water wells, and the use of high steam pressures

are all factors that the careful engineer would take into account when designing an air plant from which the highest efficiency is required.

The power driven compressor plant.—The recent (1919-1920) high market value of fuel oil has made all but the most carefully designed steam driven air compressor plants very heavy expense burdens to the companies operating them. The advent of the reliable and simple oil engine with its fuel economy of 0.5 pounds of fuel oil per brake horsepower hour delivered has made possible the oil-engine-driven air compressor plant requiring from 1-6 to 1-7 of the total daily fuel oil consumption of the average well constructed steam-driven plant.

Where oil engines are used, both the engine and compressor are fully as portable as the steam driven compressor and the oil field boiler. While the initial investment cost of this class of compressor plant is high, it will usually pay its added cost over that of the steam driven plant in less than one year's time with oil at $3.00 or $3.50 per barrel .

With **electrification** of oil wells for pumping introduced in many pools, the air compressor plant can be **motor driven** with several distinct advantages.

First: Low initial cost.

Second: Minimum operating expense.

Third: Synchronous motors can be used for driving the air compressors and their excitation adjusted so that the power factor of the electric load on the central station can be brought up from the usual 60 to 90 per cent or better.

Air transmission.—Oil operators seem to have the entirely erroneous impression that a great deal of power is lost in friction in transmitting air in pipes at high pressure for oil field distribution. Such is not the case, and it must be remembered in making calculation that at a pressure of 500 pounds per syuare inch relatively small volumes of air are being handled. In one case that came under the writer's observation the discharge from a 308-foot steam driven Ingersoll-Rand compressor delivering at 500 pounds per square inch at the compressor discharge, showed a pressure of 493 pounds per square inch at a point 4000 feet away when discharging through two-inch tubing. This pressure drop coincided almost exactly with the calculated pressure drop for these conditions.

Auxiliary compressor.—One very frequent loss of power in oil field air compressor plants is that of using a 500-pound per square inch pressure compressor to blow a low lift water well on which a 100-pound per square inch compressor would give ample pressure. The use of a high pressure machine for low pressure work is most uneconomical and is a practice that ought not to be permitted where economy of fuel is essential. Likewise, the **operation of steam pumps** and **steam engines** should not be permitted with high pressure (500 pounds per square inch) air. The use of compressed air for these purposes is uneconomical at best and a 100-pound per square inch pressure compressor should be installed. Where this use of air is necessary a preheater should be installed to raise the temperature of the air before it enters the pump or engine cylinder. Further the clearance in the pumps or engine cylinder should be reduced as much as possibly can be done by installing false piston heads and followers on the engine or pump piston.

Bibliography.—U. S. Bureau of Mines Technical Paper No. 70, "Methods of Oil Recovery in California," By Ralph Arnold and D. R. Garfias. Bureau of Mines Publication No. 148, "Methods of Increasing the Recovery of Oil From Wells," By J. O. Lewis. "Compressed Air Data," by W. L. Saunders and C. A. Hirshberg, published by Compressed Air Magazine, New York City. "Pumping by Compressed Air in the Baku Fields," Paper by Mr. R. Stirling, Institution of Petroleum Technology, London, England.

LEASE MANAGEMENT IN THE GULF COAST FIELDS

A common criticism of large producing companies is that they do too much operating in the office and not enough in the field. While this is true only to a minor degree it is a well known fact that after the production on a lease has fallen so low that a large company cannot operate it at a profit a private individual can take hold of it and make it pay a handsome return. Examples of this can be found in any Gulf Coast field. This is simply because of the fact that the private individual is on the ground all the time and makes an intensive and detailed study of every acre of his lease to see if there is any place where he is losing oil or failing to get as much as he should. On account of the extensive holdings of large companies intensive studies of small producing properties by competent men are not always possible. However, the following remarks apply to properties of most any size and may be found of interest to both the large and small producer.

The waste of fuel oil.—As the price of Coastal crude increases operators will begin to look around to see how they can possibly save some of the oil that is now going up the chimneys in the boiler plant. In the Gulf Coast fields, taken as a whole, nearly one-eighth, or 12½ per cent. of the production from the wells never sees the market, but is used up as fuel for running steam engines, pumps and in treating oil: or is lost by being stored in earthen pits. By using modern and efficient methods this fuel consumption can be reduced to four per cent or less. With the Coastal fields producing over 100,000 barrels of oil per day this would mean an annual saving to operators of about 3,000,000 barrels of oil.

Everyone knows that the common oil field steam engine and steam pump are the most wasteful types of prime movers. Too extensive use of steam power is responsible for a great deal of the waste of crude oil. It is possible to operate large leases without employing steam power on them.

Many of the smaller companies allow their production to run out into earthen sumps or pits where the same is treated before being pumped to storage. The waste here is considerable in sandy soils, although every small producer will argue to the contrary. This is a pure waste of oil and can be easily corrected by installing proper treating devices and the saving in production will soon pay for them.

Small average production of wells.—In any field during the "gusher" days the problem of production management is relatively unimportant. Handsome profits are being realized and it is hard to make mismanagement show up. However, the "gushers" take care of themselves once they are brought in properly and the problem resolves itself into one of handling the small producers. In the Humble field at present there are close to 550 producing wells. With a daily average production at the time this was being written of about 12,000 barrels for the field this makes the daily average production per well run close to 22 barrels. In the fields where there are not so many large producing wells the daily average per well is much lower. In Saratoga field, for instance, the daily average production per well for the month of January, 1917, was 7.4 barrels. At Batson the average production per well will run close to 4.5 barrels. It will be seen, then, that the big problem in the Gulf Coast Country today is not how to handle the gushers, but rather

how to handle a large number of small producing wells in order to make them realize a good profit on the investment.

The standard rig.—In the Coastal fields when a well is brought in that does not flow and is isolated from a pumping power it is "put on the beam" in order to pump it. This necessitates the building of a standard rig. The standard rig is a device designed in the Appalachian section and used universally in "hard rock" oil fields for operating a string of standard cable tools. It usually costs about $1500 to rig an ordinary well to pump with a standard rig and four to five days' time is usually lost in so doing. It seems absurd that after completing a well with rotary tools, operators should be forced to build a standard rig in order to pump it. Pumping a well with a "steam head" or using compressed air are exceptions that find application in but relatively few cases.

Many Gulf Coast operators are now figuring on devices which can be set up on a derrick floor in a short time and which will give the same reciprocal motion as the familiar walking beam. Field men in the Caddo, La., district have been active in working on this problem and several devices have been patented for taking the place of the standard rig. Two of the oil well supply houses now manufacture a structural steel pumping unit that can be set up on a derrick floor immediately the well is completed and the well put to pumping. Rods and tubing can be pulled with them and the well bailed the same as with the standard rig. In criticising these outfits it might be said that they are a little too light in construction for moderately deep wells in this country. However, it is very probable that before many months some reliable concern will have on the market a pumping device that will cost in the neighborhood of $500 which can be set up on a derrick floor in a few hours, and which will do everything that is now being done by the standard rig. These outfits ought to be so made that they can be run with a steam engine, electric motor, gas engine, crude oil engine, or any kind of power that is available. It may be that within a few years we will regard the ordinary standard rig in this country with the same disdain that the modern rotary machinery manufacturer regards the early efforts in that field.

The standard rig is all right in the Eastern, Mid-Continent and Pacific Coast fields where drilling is prosecuted to a large extent with cable tools, but in the Gulf Coast country it is a makeshift at

best and stands as a reflection upon the ability of the operators that it has not long since been replaced by something more adaptable to this section. In this country, where the rotary system of drilling has been created and perfected to such a point that it now finds application all over the globe, there are certainly plenty of men eminently qualified for working out a detail that will make a rotary-drilled well independent of cable tool devices from start to finish.

The steam pump.—In traveling around over a lease in the Coastal fields one usually notes numerous steam pumps in use handling oil. The ordinary 10x6x10 duplex pump working at a moderately fast rate will consume almost twice as much steam as a 10½x12 steam engine. For handling reasonably larger amounts of 19 degrees Beaume oil over distances up to one mile through 2½-inch or larger pipe, a "tail-pump" made up of an old working barrel and mounted on the pitman end of a walking beam will be found just as satisfactory as a steam pump. On leases where there are no standard rigs, and where all wells pump from jacks, a weighted jack mounted over a sump and operating a short working-barrel will handle the production very satisfactorily. There is now being marketed a rod line pump which works on the jack line leading from a pumping power to the well. They are being used quite extensively by some operators. Quite a few small operators are gradually getting around to the opinion that a steam pump has no place on a lease.

Developing a lease.—In the development of a small-producing property the wells, as they come in, are put on a standard rig; each rig being run either by a steam engine, or possibly a gas engine where sufficient gas is available. If steam is used as more wells are drilled it is supplied from a central station. As development proceeds the company finds that it has possibly thousands of feet of steam lines scattered around over the lease and the loss by condensation is considerable, even if the lines are covered with magnesia or other insulating covering. The fuel consumption for generating steam finally reaches such a high figure that steps are taken to handle the wells without the continual use of steam at each well. Usually, pumping powers are installed with 20 to 25 wells being pumped with jack lines from each power. A 35 to 50 horsepower engine is installed in the power. Both gas and steam engines are used for this service and it is quite the custom to install both kinds

of engines in each power; the steam engine to be used in emergencies. On leases where the gas pressure is weak it is beginning to be the custom to use crude oil engines in powers. Electric motors are well adapted to this work and many are in use in the Coastal fields; but, as yet, they have not come into prominence, mainly on account of the high cost of electric power.

Compressed air use.—In the Salt Lake oil field near Los Angeles, California, on the property of the Rancho la Brea Oil Company, when the steam consumption became prohibitive air compressors were installed and 60 standard rig steam engines on the lease were run with compressed air, same being furnished through the old steam lines. In this way there was but a slight loss of power in transmitting the air and they were able to utilize all of their old machinery. Points to be noted in converting a lease from steam to compressed air power are as follows:

1. First, ⅜-inch, or larger plates should be riveted on each end of the pistons so that there will not be so much displacement in the ends of the cylinders.

2. All standard rigs should be run with air at a pressure of about 20 pounds per square inch. For pulling rods and tubing 60 pounds of air will be necessary. All walking beams should be counter weighted.

3. Preheaters are required at each standard rig to heat the air before it goes into the engines so as to avoid refrigeration. These heaters are fired with gas and it costs about $12.00 to equip each standard rig with a preheater. The air should be heated to 250 degrees Fahrenheit, otherwise ice will form in the valves.

4. A standard rig running at 20 lifts per minute requires 86 cubic feet of free air per minute to run the engine. This for a 1500-foot hole with oil ranging from 11 degrees to 18 degrees Baume and plunger pumps. A 20 by 24 single stage compressor running at 90 revolutions per minute will handle 10 wells at 20 pounds pressure.

5. In drilling wells with air instead of steam it was found that 80 pounds of air was about as efficient as 125 pounds of steam and much quicker.

6. For lubrication tallow cups tapped into the cylinder or into the air inlet pipe must be used. Most any kind of oil will work in this cup.

This type of power should work very well in the Gulf Coast country on a lease having a large number of moderately deep wells to handle. Compressed air power is not very expensive when generated at low pressure by gas engine or Diesel engine driven, direct connected single stage compressors.

Pumping powers.—The main idea of a pumping power is to develop a horizontal pull of about 16 to 18 inches by the movement of a steel ring inside of which an eccentrically mounted spindle revolves. This has been perfected through several stages until today the most up-to-date type of pumping power is the underpull band wheel type. This consists of a steel band wheel 18 feet or more in diameter on the periphery of which a 12-inch, 6-ply belt some 130 feet long runs and transmits the power from the gas engine, steam engine, crude oil engine, or motor. The eccentric straps or rings are mounted under the wheel and as many as 35 wells can be pulled from one of these powers. The wells should be equally distributed on all sides of the power, or carried into the band wheel from different directions, by swings, etc., in order to balance the load on the wheel. If the load is not balanced it tends to make the wheel run out of line. As considerable strain is thrown on the wheel it should be well set in concrete. With fairly good subsoil it is customary to make the concrete block in which the power is imbedded 10x10 feet in area and 5 feet deep. With quick sand sub-soil it is well to give the base of the block a considerable amount of "spread."

The speed at which band wheels are run varies greatly with different operators. Some claim that the faster the power is run the more oil is gotten and hence it is speeded up so as to get as many as 26 lifts of the jack per minute. Others hold that up to a certain point all the oil will be gotten by running slower and their powers are operated so as to get 15 to 20 lifts of the jack per minute. It is certainly true that conditions vary widely on different leases and that a speed which is best for wells on one lease is not suited to a set of wells on another.

New type jack lines.—Jack lines or "jerk lines" made of ⅝-inch steel rods are used to transmit the motion from the power to the jack at the well. Heretofore it has been customary to let these lines slide back and forth on top of posts or through holes bored in the posts. These friction surfaces are usually spaced about 30 feet

apart and are kept well greased with axle grease. Considerable power is lost by having the rods pull over or through posts. With 20 wells on a power and each well averaging 800 feet in distance from the power there would be about 540 friction surfaces. Using oak, pecan, or maple wood, it can be seen that at least 10 to 12 horsepower would be used up in overcoming this friction. Operators in the Gulf Coast country are just beginning to use the swinging type of jack line, where the line is swung from a pendulum-like rod attached to a post or piece of 2½-inch pipe driven in the ground. The friction loss here is neglible.

Gas Engines.—The cheapest form of power for operating a band wheel power is the gas engine as long as a good supply of gas is available. In many of the coastal fields gas is getting rather scarce and the operators are looking for something to take its place. In localities where electric power is cheap gas engines are being replaced by electric motors. These are the most satisfactory form of power for running the pumping powers. In the Gulf Coast country the operators are slowly adopting crude oil engines of the low compression or semi-Diesel type.

CRUDE OIL ENGINES

Crude Oil Engines are those which burn their fuel indirectly in the engine cylinder or in a vaporizer directly attached thereto. In this respect they are different from gasoline engines which require carburation. They are operated on the Diesel principle and burn any grade of crude petroleum or fuel oil.

In principle of operation, they are divided in two parts, Diesel and Semi-Diesel.

The Diesel (or full Diesel) is operated under two principles. First, the engine that injects the oil or fuel into the cylinder and with the aid of high pressure air, which air effects the vaporization of the fuel; second, the engine which injects the fuel into the cylinder with high fuel pump pressure, this being so high that its force vaporizes the oil.

The Semi-Diesel engine operates on the principle of injecting the fuel into the engine cylinder or into a vaporizer attached thereto at a comparatively low pressure, but the fuel is injected against a hot tube or a hot head, which is a factor in the ignition of the fuel.

There is another type of crude oil engine in which the fuel is

injected at low fuel pump pressure into a cup or tube and where the fuel becomes vaporized and the gas therefrom is expelled out of the holes in the tube.

For the full Diesel with air injection we can refer to the Snow; for the full Diesel with fuel pump injection and no air we can refer to the De La Vergne Type "SI", for the Semi-Diesel with a vaporizer we can refer to the De La Vergne Type "HA", for the Semi-Diesel where the fuel is injected into the cylinder we can refer to the Bessemer type IV; for the engine operating on the full Diesel cycle and using the cup or tube principle we can refer to the St. Mary's.

The oil engines are divided into two classes fundamentally two-cycle and four-cycle and as far as the differences in these two engines are concerned these differences are the same as those of the two-cycle or four-cycle gasoline engine with the exception that most two-cycle oil engines require additional scavenging because of the gases from crude oil being more impure than the gases from gasoline.

The economics of these engines vary from 0.75 pound of fuel per bhp hour down to 0.35 pound of fuel per bhp hour, depending upon whether they are the full Diesel or Semi-Diesel. In the case of the full Diesel, the economy depends on whether they use air injection or fuel pump injection. The Semi-Diesel will vary from 0.75 pound to 0.6 pound fuel per bhp hour. The full Diesel with air injection will vary from 0.6 to 0.48 pound. The full Diesel without air injection and fuel pump injection will vary from 0.48 to 0.35 pound. The operation of the crude oil engine depends upon the vaporization of the fuel. The better the vaporization the better the operation and the less carbonizing on the inside of the engine cylinder. The better the vaporizer the better the fuel is consumed.

The real principle of the operation of these engines is as follows: First, in the full Diesel, the compression of the engine is so high that the temperatures resulting therefrom are higher than the flash point of the oil consequently ignition occurs. Second, in the Semi-Diesel, the compression, together with the heat of the hot tube or hot head, is so high that it affects ignition of the fuel. Therefore it can be seen that the full Diesel operates at higher pressure than the Semi-Diesel. Thus it is very evident that oil engines operate at higher temperatures and higher strains throughout the whole mech-

anism than steam engines. Consequently, the oil engine is a more delicate piece of machinery, but its economics are so much higher than the economics of the steam engine and boilers that the difference in price and maintenance are offset by the fuel saving.

Oil engines, because of the principles of design are incapable of overload. This is also true of gasoline and gas engines.

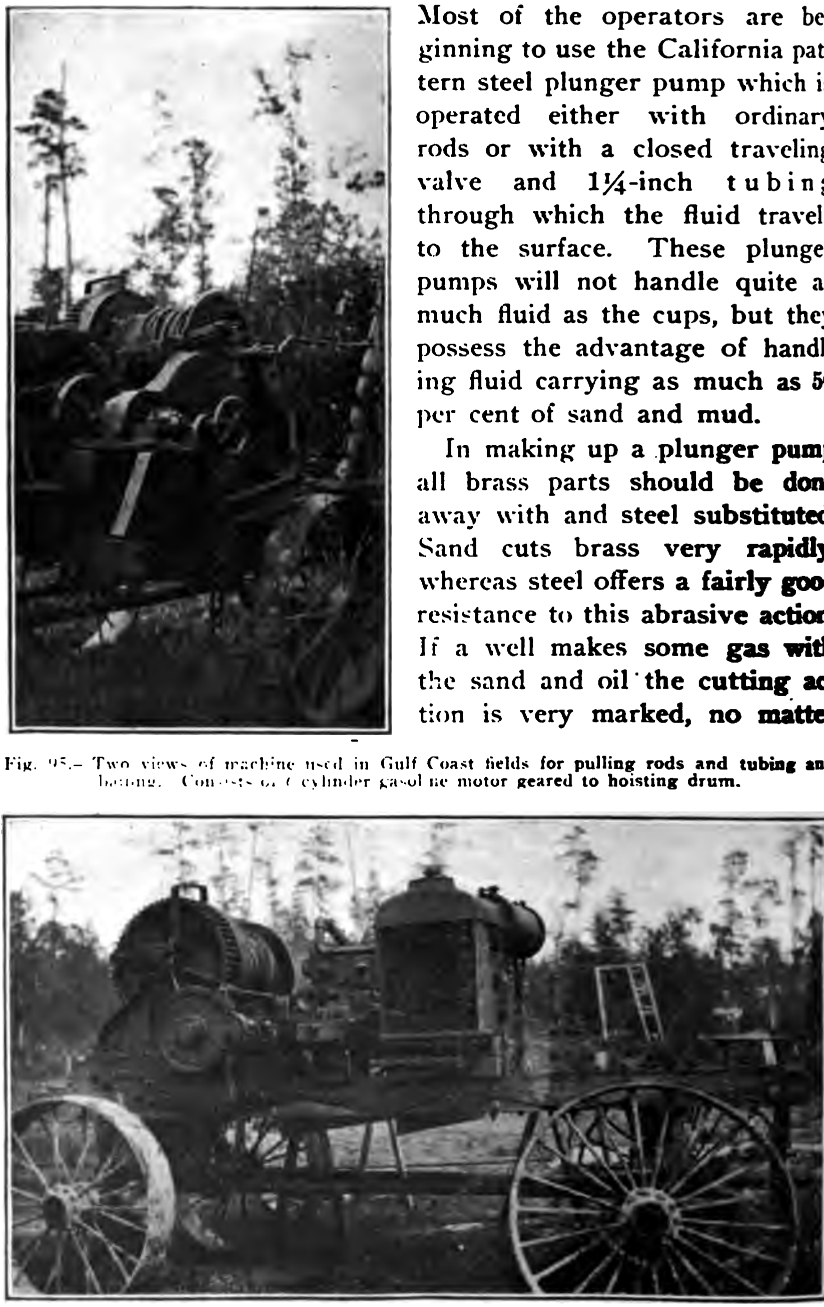
There is another type of engine known as the sulphur pit or mercury cup oil engine. For details on this we can refer to the new Bessemer engine. The Bessemer 25 h. p. "O. D." type oil engine under test in California for operating of standard rig well pumping equipment gave the following results:

Days operating	68	
Hours operating	1632	
Gallons fuel 21 degrees used	1433	
Estimated h.p. when pumping	7	
Fuel consumption	.1255	gallons per h. p. hour.
Lubricating oil used per day	1	quart.
Cost per day (fuel oil at $1.58 per barrel).		
Fuel		$0.792
Lubrication		0.40
		$1.192

Because of its fuel saving there are many places in the oil fields where oil engines can be used. It is becoming common practice to use oil engines in pumping oil in pipe lines in the fields, for running pumping powers, and now the Bessemer Engine Company and the Fairbanks Company have an engine in successful operation on individual wells for pumping and pulling. The oil engine can be recommended very highly because of its efficiency and its low fuel consumption.

Getting the oil out of the well.—Taken as a whole, the pumping wells of the Gulf Coast country probably give more trouble than those in any other section of the United States. The presence of fine sand which sooner or later enters the hole in varying quantities is due in the old wells to the strainer giving away, and in the new wells to coarse strainer being set. Quite a few of the wells produce an emulsion of oil, water, and sand that is pretty hard on any type of pump.

Handling sand wells.—In handling sand wells the old style pump, which handles the fluid with cups, has to be done away with.



Most of the operators are beginning to use the California pattern steel plunger pump which is operated either with ordinary rods or with a closed traveling valve and 1¼-inch tubing through which the fluid travels to the surface. These plunger pumps will not handle quite as much fluid as the cups, but they possess the advantage of handling fluid carrying as much as 50 per cent of sand and mud.

In making up a plunger pump all brass parts should be done away with and steel substituted. Sand cuts brass very rapidly, whereas steel offers a fairly good resistance to this abrasive action. If a well makes some gas with the sand and oil the cutting action is very marked, no matter

Fig. 95.— Two views of machine used in Gulf Coast fields for pulling rods and tubing and bailing. Consists of [illegible] cylinder gasoline motor geared to hoisting drum.

what kind of metal is used. A gas anchor, made up of an extra length of perforated tubing and located beneath the working barrel, tends to keep the gas out of the barrel. These anchors should be used to a far greater extent than they are at present.

Tubing catchers.—In the most of the Gulf Coast wells the tubing is suspended in the hole, usually hanging several hundred feet off bottom. Many good wells are ruined by a string of tubing parting in the hole and dropping to the bottom or else dropping while being pulled from the well. In some sections a newly-patented tubing catcher is finding a wide application. With this device attached to the bottom of a string of tubing it is impossible for the tubing to drop in the hole.

Fig. 95A.—The Franklin Pulling Machine.

Devices for pulling rods and tubing and bailing.—As the wells on a lease are hooked up to the pumping power and the standard rigs are done away with the question of proper equipment for pulling rods and tubing, and bailing arises. In the Gulf Coast country there are about as many solutions to this problem as there are leases.

Some companies maintain a standard rig at about one well in

five and pull rods "across country" by having blocks anchored in the derrick floors through which the lines operate from the crown blocks in the derricks. Such a method is very unsatisfactory as the man operating the steam engine is too far from the well where operations are being carried on and hence cannot watch things closely. Accidents often result from this cause. Some operators place a small draw works and engine at every well. This system is too costly on a large lease.


Fig. 95B.—The Clark Pulling Machine.

Other operators are coming to use a "hoisting machine." This is nothing more than a Lidgerwood, or similar type, steam hoist, with two small steam cylinders of about 5 horsepower each, mounted on a wagon frame, and it is pulled around from well to well as needed. Operation of this machine necessitates having steam piped to each well. As the wells may be isolated from the boiler station, this means wet steam and consequently a "logy" engine. The loss of power here is quite an

item. Wagon frames for carrying this hoist should have steel wheels with tires not less than 6 inches wide in order to be easily pulled around in any kind of weather.

The latest hoisting machine in use in the coastal country consists of a hoisting drum gear driven by a six-cylinder distillate engine. They are very economical. One of the caterpiller tractor companies also sells a device which goes with their tractor and pull rods and tubing very satisfactorily. (See Figs. 95-A and 95-B.)

In many of the "shallow sand" districts operators are doing away with derricks after the wells are drilled and pull rods and tubing with a portable "pulling machine." This outfit, as used at Batson, consists of three joints of pipe which telescope one within the other and which are mounted on a wagon frame. A small drum on the base of the largest joint of pipe is used for spooling the tubing line and this is operated by horsepower. In the Saratoga field on the Rio Bravo Oil Company's holdings, a similar device is in use, but it is operated by a small steam turbine engine mounted on the bed of the wagon and connected to the drum by a chain drive.

On the Texas Company property at Sour Lake a traction well puller and cleaner operated with a distillate engine is in use. This outfit carries a portable, telescoping mast and the drum is operated from the engine. It moves to a well under its own power and is absolutely independent of steam or horse power.

In the Kern River oil field of California a device is being used for pulling rods and tubing and bailing wells that gives very good service. It consists of a three-ton, chain-driven, motor truck on the bed of which is bolted a hoisting drum. The truck is run up to a well and the chain drive disconnected from the rear axle and connected to a sprocket on the hoisting drum. Bailing or pulling rods and tubing starts as soon as the clutch on the truck engine is let in. This truck can handle 800 feet of three-inch tubing in the high gear. Running in low gear it is much more powerful. When this truck is not needed at the wells it is run into the shop where a crane removes the hoisting drum and it is then available for hauling pipe or any kind of supplies. A more convertible or convenient source of power would be hard to imagine.

In the same field a hoisting outfit operated by an electric motor is used. These are ideal where electric power is available.

Keeping production off of the ground.—Where an operator has

several wells making large quantities of sand, water and emulsion it sometimes seems foolish to talk about pumping such a mess through pipe lines. Hence the practice is to let the fluid, or semi-fluid mass, flow out into an earthen pit where the sand and water separate to a certain extent. The top portion of this fluid is then pumped to the treating tanks. Needless to say, a large amount of oil is lost by seepage into the walls of the pit. The separation outlined above can be effected very nicely by letting the production flow into a "sand box." This is nothing more or less than a tin-lined box about 2 feet by 3 feet in cross section and 20 or 30 feet

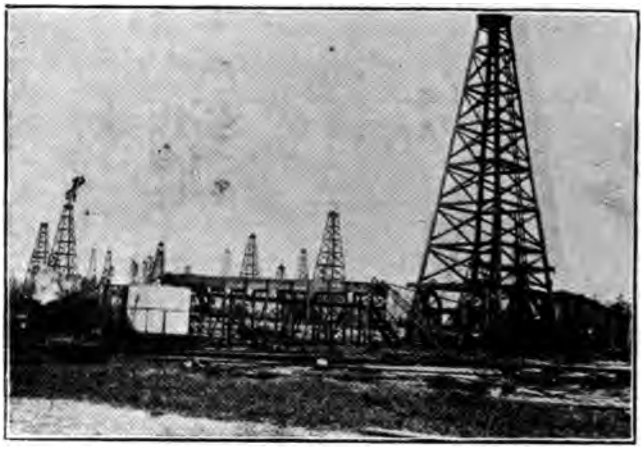


Fig. 96.—Sand box in the Saratoga field. The oil is pumped into a sand box. The sand is caught by baffles in the box, and is shoveled out periodically by the pumper. The water is bled out of the bottom of the box. The oil goes into galvanized tanks, as shown to the left.

long, supported above the ground by a framework and sloping about 12 inches in the 20 feet. Baffles are placed in this trough about every 5 feet. The sand, water, and oil are pumped into the upper part of the trough and the sand is separated out at the baffles. A pumper shovels this sand out of the box as often as is necessary. The fluid passes over the baffles and the top portion, which is mostly oil, flows into galvanized iron settling tanks. The water is bled out of the bottom part of the trough. One of these sand troughs can accommodate eight or ten wells and it will pay for itself in a short time. The production is pumped from the galvanized tanks to the treating tanks. (See Fig 96).

RECOVERING OIL FROM UNCONSOLIDATED SANDS[1]

The process of obtaining oil from the earth when that oil is contained in a loose unconsolidated sand is very different from the method employed to extract the recoverable portion of the oil content of a hard stratum. With an unconsolidated sand the extract-tracting of its oil content may take place above ground whereas with a hard oil-bearing stratum this is impossible. This distinction has an important bearing upon all questions relating to oil production. It is the factor deserving the greatest consideration in determining the efficiency of methods employed for the maximum recovery of oil from unconsolidated sands and is the basic principle of the statement that: Other things being equal, the maximum recovery of oil from an unconsolidated sand is directly dependent upon the maximum recovery of the sand itself.

The truth of this law is based upon two important considerations: (1) The removal of sand by a well causes a larger volume of sand, and therefore of oil, to move toward that well than would be the case if oil only were removed. (2) The efficient separation of sand and oil, and therefore a nearer approach to obtaining the recoverable oil content, is made when this separation takes place above ground.

The movement of sand and oil toward a well.—The higher the viscosity and the lower the gas pressure within the oil reservoir the greater becomes the importance of creating and maintaining a movement of sand toward a producing well. This has been proved beyond all question in extensive operations in the north Midway district of California where the oil is of 14.5° Be' gravity with a very low gas pressure.

"In the Balakhany oil district, where the oil is heavy, and the gas has nearly all escaped from innumerable wells, the concentration of the petroleum toward old producing areas is very marked, and whilst old bailing properties, which have for many years yielded a moderate payable production show little or no fall-off, new lands interspersed between these are almost valueless and give practically no output when new wells are sunk. This is additional testimony of the movement of oil towards spots where immense quantities of sand have been removed by bailing, creating areas of low density into which the petroleum, no longer assisted by a gas

[1]Wm. Kobbe in Trans. A. I. M. E., Vol. LVI.

pressure, percolates by gravitation. In one case, a new well bored in the Balakhany district was a distinct failure, for stratum after stratum failed to yield even a mean production, but an old well which had been bailed for many years before abandonment, gave, when cleaned out, the extraordinary production of 2,500 poods a day for more than a month, and then only fell off by degrees to 400 poods daily."

The fact that large producers come in without "making sand" is evidence of existence of high gas pressure and insufficient means of entry for the sand to pass into the casing, but it is not proof that the large production is due to the absence of sand or that the output would not be increased if sand were expelled with the oil.

With proper mechanical arrangements a well tapping a thick stratum of unconsolidated pay produces a tremendous amount of sand. That it continues to do this for long periods is proof that a constant replenishment takes place near the casing, necessitating a movement of sand and oil toward the well. This movement is frequently of such volume, or occurs so suddenly, that the casing penetrating the reservoir is damaged or completely severed from the upper and more rigid portion of the string. Several instances of such damage may be mentioned: In one case 250 feet of 36-lb. 8¼-inch casing was twisted somewhat in the shape of the letter S and was removed from the well only with the greatest difficulty. In another instance several hundred feet of 6¼-inch 20-lb. casing was broken just below a collar and displaced to such an extent that no part of it was touched by the tools while repairing the damage. Several cases may be cited where casing has been so deflected or bent by sand movements that it was impossible to tube the well beyond the point of flexure. No type of casing is proof against this force of moving sand, and both screen and perforated pipe suffer ,although it is believed the former less so than the latter. Likewise it appears to make but little difference whether the casing passes entirely through the sand and is anchored in an underlying stratum or penetrates for only half the distance.

Methods of extraction.—In order to bring about a movement of sand with its oil content toward the well, it is necessary to provide means for its efficient removal with special casing devised to facilitate this process. If the sand cannot enter the casing, not only is

the movement of oil retarded but the sand surrounding the casing is partially drained of its oil content, resulting in a constantly body of "dead" sand opposed to the richer portions of the reservoir. Instances are known where a well, because of faulty perforations or inadequate screen openings, produced small quantities of clean oil free from sand for several years and when an attempt was made to substitute screen with proper-size mesh the sand had become so "dead" in the vicinity of the well that it lacked the "life" to enter the casing and continued to obstruct the path of better "pay." The same conditions apparently explain similar failures when a well was reperforated, but in such a case there is always the element of doubt that arises whenever a perforating machine is used. These cases occurred with a very loose oil sand containing an asphaltic crude of 14.5° Be' gravity and were undoubtedly influenced by nearby wells having established strong drainage channels. In any event, the fact remains that they produced no sand and very little oil, and that these conditions could not be improved. Furthermore, there was no local variation in the reservoir or other controlling factors to account for this phenomenon.

On the other hand, when a well is properly equipped and produces great quantities of sand with the oil a large area of lower density is gradually established around the casing and, unless encroaching water is present in quantity, this removal of sand must inevitably lead to the formation of a cavity. This cavity probably assumes the form of an inverted cone as sand continues to be removed while new sand with its oil flows by gravity down the slopes of this subterranean funnel and supplies the well with fresh material. The shape of the cavity is undoubtedly influenced by the dip of the strata, when marked, and by the disturbing effect of nearby wells. That a cavity forms, however, cannot be disputed. Sand slips, damaged casing, and collapse of the cover rock evidence such a cavity in addition to the impossibility of otherwise explaining the effect of removing the tremendous volume of sand that wells have been known to produce.

It would be interesting to know when the slopes of these cavities reach an angle of repose and experiments with saturated oil sand on the surface should prove most instructive. The fact that wells producing from unconsolidated pay sands gradually diminish

in their output of sand may indicate the approaching stability of these underground slopes, and evidence presented in later paragraphs strengthens such belief.

Having attempted to show the necessity, not only of removing sand in order to recover the maximum quantity of oil, but the favorable results of such removal in cavity formation with its accompanying low pressures and "live slips," the mechanical handling of this sand will now be described.

Function of screen casing.—Screen casing of proper mesh serves its best usefulness in permitting the regulated entry of the maximum amount of sand and oil while excluding gravel and small stones which would "sand up" the pump by sticking the valves, or otherwise prevent its proper action. It probably serves another use in that it results in a more even distribution of the oil and sand channels radiating from the well than is the case with ordinary perforations. This even drainage of sand and oil equalizes the pressure in all directions around the casing, whereas the use of a perforating machine may result in the sand being drained from one side more than the other, thus creating a pressure against the casing. This unequal drainage due to faulty perforation is an argument for the use of screen pipe and a possible explanation of deflection and damage to oil strings.

One type of wire-wound screen utilizes "keystone wires" whose function is to prevent clogging of the mesh—the space between the wires increasing radially and thus permitting any substance that enters to pass through unhindered. An exceptionally large screening surface is exposed to the sand with this type in that the wires between the perforations are utilized as fully as those directly over the openings.

Another type called "wireless" or "button" screen is especially adapted for work with cable tools, as it will withstand hard usage and the driving and pulling often necessary with that system in drilling through unconsolidated sands.

The selection of the proper-sized mesh depends upon the physical character of the sand, viscosity of the oil and the gas pressure. The mesh should be of sufficient size to allow the maximum entry of sand and oil while excluding pebbles and small stones. This is best determined by practical experiment above ground. Other things being equal, a high-viscosity oil demands a coarser mesh

than one of low viscosity. A screen made up of five wires to the inch proved most effective with a moderately fine sand carrying oil of 14° to 15° Be'. gravity. The erroneous belief that the function of screen casing is to prevent the entry of sand in oil wells, with the consequent avoidance of pumping troubles, leads to the selection of too fine a mesh in many instances. The mesh should be too coarse rather than too fine. Screen pipe came into use and was devised in connection with water wells and it was natural that the same rules were thought applicable when it was introduced in the oil fields.

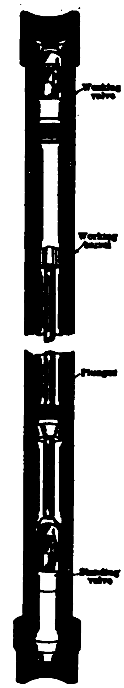


Fig. 97
Cross section of working barrel of plunger pump.

Pumping the sand and oil.—Assuming that a well has been properly drilled, thoroughly washed, screen casing set, and that sand and oil are passing freely through the mesh, the most efficient device to bring the sand and oil to the surface is the plunger pump (Fig. 97). Although many wells flow naturally for a time or may be agitated by periodically moving an "agitator string," and others containing much water may be pumped with an air lift, the standard equipment for handling sand is the plunger pump. This device consists essentially of an outside cylinder or "working barrel" and a hollow plunger with upper and lower valves (Fig. 97). Although simple in principle, these pumps are very carefully made of the best material and ground to an exact fit, and their proper installation and operation require experience and knowledge in order to obtain the best results in the removal of the sand. The working barrels are made in lengths from 42 to 60 inches and from 2 to 4 inches diameter. A common size is 3 by 60 inches for the "renewable" or liner pump with extension and top collars at both ends. This is one of the best types of pumps for handling sand, as the upper portion of the plunger does not leave the barrel and therefore is not in contact with sand on its downward stroke. The standing valve barrel is carried on a 3 by 24 inch nipple which allows the plunger to pass below the lower end of the barrel on each stroke, thus retarding the entry of sand between the plunger and barrel.

Pump operation.—A properly installed and operated plunger

pump will handle a surprising quantity of sand; in fact, it may be said that it is capable of pumping sand containing oil rather than oil containing sand. It is not at all unusual for one of these pumps to handle a mixture containing 50 per cent of sand by volume. A careful record should be kept of the performance of the pump on each well; depth at which it is pumping, date when new valve seats or balls were substituted for the old, when the barrel was renewed and on what date the tubing was lowered. The lasting qualities of a pump are directly dependent upon the quantity of sand produced and as this varies with each well the importance of keeping a record of pump performance is apparent. A barrel may require renewal every six weeks on one well while on another it shows but slight wear after three months' use.

The common practice of allowing a well to pump until the barrel becomes so worn that the production dwindles to a small stream or until some accident or breakage necessitates pulling should be condenmned. Each pumping well should be studied and every effort made to maintain the production not only of oil but of sand.

The well should be tubed to such a depth that the maximum quantity of sand which the pump is capable of handling reaches the barrel at all times. This point can be determined only by experiment and gradual lowering of the tubing as sand production diminishes. Continued pumping of sand may save expense and labor of cleaning out "dead" sand with tools and bailer.

In order to determine the exact condition of the barrel and plunger it is essential that both be removed from the well, washed with distillate and then tested for fit and the absence of lateral play between the plunger and the barrel.

The common practice of removing only the rods and plunger for examination is to be condemned.

The pumping of sand is troublesome and means much work around the wells. For this reason there is a tendency to avoid it.

A long stroke is advisable for pumping wells producing sand and the wrist pin should be carried in the "second hole."

If a valve becomes clogged with small gravel or sand it may often be freed by "shaking up the well" or running the pump at high speed for a few strokes. Twenty-five strokes to the minute is the usual pumping rate when the rods drop freely and prevents the sand from settling.

Hot Oiling[1]

Methods of overcoming a decline in production.—After a well has produced sand for a time varying from months to years it gradually diminishes in output even though the well is tubed to bottom. In such cases several methods are used to "liven up" the well and increase production. Steam has been used in such wells and "swabbing" is commonly practiced, but the best method is probably the introduction of hot crude oil. Where this method fails it is undoubtedly caused by faulty casing, either screen or perforated, or the hot oil is improperly applied.

The best practice is to heat about 100 barrels of crude almost to the boiling point and allow it to flow by gravity or pump it down the well casing. It is usually treated in a nearby tank with steam coils and although some operators introduce it through the tubing this practice has the disadvantage that the necessary stoppage of the pump may cause it to sand up.

The effect of the hot oil is to wash the screen or perforations and to lower the viscosity of the underground supply, causing both the oil and sand to flow more readily toward the well.

The hot oil need not remain in the well for more than one-half to three-fourths of an hour and is then pumped out together with large quantities of sand and "live" oil, oftentimes acompanied by considerable gas. It frequently happens that so much sand enters the well following this treatment that the pump is unable to handle it, in which case two or three joints of tubing are removed, the barrel afterward being gradually lowered as the sand becomes exhausted. After a few weeks the pump again reaches bottom, when another hot oiling is given.

There is no fixed rule as to the frequency of this treatment. This can be determined only by experiment and is largely dependent upon the age of the wells. In some cases it may be applied once a week with beneficial results while in others once a month is sufficient.

Quantity of sand produced.—This is a most interesting subject but, unfortunately, exact figures on the actual quantity of sand produced by flowing or pumping wells are unavailable.

In speaking of the sand produced by wells in Russia, Mr. Thompson says: "The oil from fountains is commonly accompa-

[1]Wm. Kobbe in Trans. A. I. M. E., Volume LVI.

nied by an equal bulk of sand, large numbers of stones, and the liberation of millions of cubic feet of gas which becomes disengaged from the oil on its exit from the tube. A recent Bibi-Eibat spouter on plat No. 29 gave as much as 10,000 tons of oil and 10,000 tons of sand in a day, and in a few weeks yielded, in addition to several million poods of oil, no less than 1,700,000 cubic feet (85,000 tons) of sand; an amount which will be better appreciated when it is realized that this quantity of material would raise the natural level of the ground on one dessiatine nearly 14 feet, or cover an acre of land to a depth of 40 feet."

The famous gushers of California and other loose-sand fields have expelled tremendous quantities of sand which in some cases have completely buried the engine house, belt house, and the lower panels of the derrick.

"In the old Sunset field wells that have a strong gas pressure produce more sand than any others in the state, it being estimated that sometimes as much as two-thirds of the gross yield of the wells is sand. One well alone produced over 110,000 cubic feet of sand in about four years, and another has yielded almost as much in two years. The yield of sand gradually decreases with the age of the well, but at no time entirely ceases. These peculiar conditions—soft sand in great quantities accompanying the flow, heavy oil, and strong gas pressure—make the problem of well operation in this field difficult."

Some pumping wells in the north Midway field produce sand at the rate of over 200,000 cubic feet a year and careful measurements would probably show that this amount is actually produced in a year or even exceeded.

Oil separation and sand disposal.—The separation of oil and sand, although more fully accomplished above ground, is one of the difficult problems connected with production from unconsolidated sands. With low-gravity, viscous oils and great volumes of sand, nothing has been found to take the place of the open-air "sump" which is simply an excavation made near the well with teams and scrapers. The sand collects in great piles in these sumps while the oil separates by gravity and is pumped from the lowest point in the depression. With heavy oil the loss through evaporation and percolation is slight, as it has been determined that it does not penetrate the ground for more than a few inches. Light oils,

however, should not be allowed to flow into sumps ,as the loss is undoubtedly great; but when accompanied by much sand other disposition is difficult. As the piles of sand are gradually freed of their oil content they become fairly dry and a crust is formed on their surface which will bear the weight of a man.

Many tanks, settling boxes and other devices have been designed for the separation of oil and sand but with little success. Most ofthese devices are entirely lacking in scientific principle and are carelessly constructed affairs designed by the workers in the fields and their failure is in large means due to these facts. An efficient means of separating light oils and sand can undoubtedly be devised and would prove of great benefit to the producer. Heavy oils being much more difficult to separate, of less market value ,and of high viscosity, may be most economically handled in properly constructed sumps.

The great disadvantage of such excavations is the space they occupy, their unsightly appearance, and the huge deposits of sand which gradually surround the well. The removal of this sand finally becomes imperative when all available space for new sumps has been utilized, but its disposal is a problem.

The only use to which it could be put in the north Midway was road surfacing and although this is possibly a very good use it is a more or less expensive one. The method used is simple.

When a sump had been drained of its oil and the sand had become sufficiently dry, it was loaded upon wagons and distributed on the many dirt roads traversing the property. The roads were sometimes dragged to prepare them for the sand but this was frequently dispensed with. A layer of sand two inches thick was sufficient to surface the ordinary road, which was immediately opened for traffic in order that the sand might become packed. The roads in that section of the country were in very poor condition, being formed from use and never constructed or built. They were deep with dust and ruts and the beneficial results attained through the use of oil sand was truly remarkable. This sand as it comes from the sumps contains sufficient oil to stain the hands and serves as a binding material for the road surface. It soon packs into a durable layer of asphaltum-like hardness. It withstands the traffic of heavy automobile trucks and is easily maintained by occasional dressings of fresh sand in the summer when the heat softens the mixture.

Further Details Concerning Pumping Equipment[1]

Other types of pumps, less commonly used in the best practices of the present day, employ various kinds of plunger packing, such as leather cups and steel rings, hemp rope, and leather and fiber rings of various kinds. Cups are used where the oil is light and carries little or no sand, as in the eastern fields. In California they are employed only after the common plunger has been slightly worn. For details of construction reference may be made to the catalogues of oil well supply houses.

The plunger of the plunger pump generally is operated by means of steel sucker rods, but in a few types by wire rope or wooden rods. It is estimated that the average life of a steel sucker rod, pumping oil of a gravity of about 0.9655 (15° B.) and containing some sand, is about two years, although in wells producing very heavy oil and great quantities of sand light rods break almost daily. Most of the rods are 30 feet in length, and the number of screw joints is sometimes reduced by welding together two or three such rods. In some properties it is customary from time to time to anneal or soften the rods by heating them in closed ovens and allowing them to cool gradually.

The life of the tubing at the end of which the pump is placed, varies greatly, but under ordinary conditions it should approximate four years. In some fields producing light oil and no sand, tubing has been used for 10 years and is still in good condition. In the crooked holes, in which the oil was heavy and carried sand, the tubing has been known to wear out in one year. One of the most important causes of wear on tubing is its repeated removal from the well. Such removal is necessary in certain territories.

A large number of the difficulties encountered in pumping wells may be traced to the wearing of rods, barrels, and valves by sand, which usually accompanies the oil. The association of oil and sand exists to a greater or lesser extent in all of the San Joaquin Valley fields and becomes extremely troublesome when the cutting action of the sand is intensified by the presence of gas under pressure. In wells where conditions accelerate the wearing action of sand, the pump barrels, valve balls, and valve seats have to be removed almost daily. In properties where no sand is encountered in the

[1]From Arnold & Garfias "Methods of Oil Recovery in California," U. S. Bureau of Mines Technical Paper No. 20.

wells it is sometimes introduced when the wells are being cleaned. This was the case in the Santa Maria field, where the rods were laid on sandy ground, and the sand, adhering to the sticky oil on the rods, was subsequently taken into the well. The trouble was easily eliminated by placing the rods on wooden platforms built for the purpose. If the balls and seats are not greatly damaged they can be ground to perfect fit by proceeding as follows:

(1) Charge a glass plate with carborundum and oil.

(2) Place the steel ball on the plate and the valve seat in position on the ball.

(3) Holding the seat in the hand, describe a figure 8, keeping the seat pressed against the ball and the ball against the plate. In order to ascertain when a perfect fit has been attained, it is necessary only to observe whether the ball adheres to the seat when a partial vacuum is created by placing the mouth against the seat and drawing the breath strongly.

The frequency of cleaning wells and replacing pump valves and barrels has a most decided effect on the producing time and, therefore, on the quantity of oil recovered and the power consumed. The time spent in cleaning is controlled by the decrease in production, and in some wells the production thus lost represents an important part in economic life.

Capacity of pump.—The theoretical capacity of the plunger pump depends on the size of the pump and the length and number of strokes per minute. The pump in most common use has an internal diameter of 2¾ inches. The pumping stroke varies from 20 to 35 inches, the average being about 20 strokes per minute.

Assuming these average pumping conditions (a 2¾-inch pump working at a speed of 20 strokes per minute, with a length of stroke of 23 inches), the ideal daily capacity, without allowance for leakage, will be about 400 barrels. Although the pumping speed and the length of stroke on which these figures are based are exceeded in actual practice, it is doubtful whether, if the losses due to leakage be included, the average working capacity of a 2¾-inch oil pump, in wells of average depth and in which gas does not help the action of the pump, can be much greater than 400 barrels a day. In actual practice, owing to the varying quality of the oil, the percentage of sand and sediment, and the generally poor condition of tubing and pumps, with consequent leakage, the results obtained are generally

much lower than this figure. It should be remembered, however, that a 400-barrel well contains, as a rule, enough gas to alter materially these figures and increase greatly the over-all production.

The figures in the following table represent actual conditions in wells of different depths, taken at random, and serve to emphasize the fact that there is no set rule to be followed in operating pumping wells and that, in order to obtain the best results, an individual study is necessary.

Records of Operation of Pumping Wells

Depth Feet	Strokes Per Min. Low	High	Av.	Production Bbls	Freq. of cleaning Months	Freq. of plungers & bbls. Days	Freq. of seats or balls Days	Age of Well Years
700	..	..	18	15	..	...	...	..
900	..	..	30	5	6	270	120	6
1000	..	..	20	40	..	90	7	14
1500	16	20	19	30	..	18	18	2.5
2000	19	22	20	100	..	20	18	2.6
2500	20	30	25	200	24	30—180	30—180	12
3000	20	26	23	180	12	30—180	30—180	12

CENTRAL-POWER AND JACK-PUMPING PLANTS[1]

A central-power and jack system for pumping oil wells is one in which power is transmitted from a central plant to the surrounding wells by purely mechanical means.

The pumping of oil wells from a central power station was a gradual development, as is shown by the number of patents allowed on different systems between 1875 and 1885. Most of the early systems were based on an oscillating motion, either a "pull-wheel system," or a "push-and-pull" system. The various pull-wheels were actuated by pitmans connected with horizontal or vertical rotating shafts. The earliest systems were developed in the Franklin and Oil Creek districts in Pennsylvania. In a typical plant the two ends of a vertical band-wheel were cranked so as to drive two horizontal pitmans were connected to a circular horizontal table in such a manner as to perform one-fourth of a revolution and then return to its former position. To the circumference of the horizontal table, from 2 to 15 connections were made in such a way that the corresponding wells were pumped by connection to

[1]Published by Mr. Roy M. Barnes in Western Engineering Magazine. Reproduced here by special permission of the author.

the pitman and walking-beam at the well. The pull came on the down stroke of the pump.

The first use of the jack systems in the California fields was when a pumping-jack at one of the wells was operated by means of a "jerk-line" attached to the crank at an adjacent well. Some of these systems are still in use. The introduction of a central pumping power usually occurs after the development days of a field are past, and it is found necessary to reduce production costs because of decline of production. The old Los Angeles City field was the first of the California oil fields in which the central power made its appearance. The other Coast Fields and the Kern River field followed, and later the older parts of the field on the west side of the San Joaquin valley. During this time, pumping by jacks has been adapted to a greater range of service, because of improved methods and heavier construction.

At the present time, pumping by means of a central power and jack-system is adapted to the operation of oil wells, where there is little trouble from either sand or water, and where the output is declining. The following are the conditions to which this method is suited:

(1) Depth. Up to 1500 feet in California, 2500 feet in Eastern Fields where the oil is lighter.

(2) Gravity. 14° Baume and lighter.

(3) Frequency of cleaning required. Up to twice a month.

(4) Production. 5 to 125 barrels per day.

(5) Position of wells. Any compact group.

(6) Topography. No limitation.

Before proceeding further let us consider briefly the construction and operation of the oil well pumps. Although varying in structural details, the mechanical principle of all the plunger pumps used in oil wells is practically the same. These pumps consist of the following parts:

1. A "working-barrel" polished on the inside, which is screwed into the end of a "string" of tubing, or else between the joints of tubing at or near the bottom of the well. In Californian practice the diameter of the tubing is usually 2, 2½ or 3 inches, and the diameter of the working-barrel conforms with this.

2. At the bottom of the working-barrel, the "standing-valve," which is a ball-valve in a cage, is attached.

3. Within the working-barrel is fitted a cylindrical plunger, polished on the outside.

4. On top of this plunger is the "working-valve," which is another ball-valve in a cage, at the top of which the "sucker-rods" are attached.

The plunger and working-valve are given a vertical reciprocating motion by means of sucker-rods, which, in California, are made of ¾ or ⅞-inch steel with joints about 20 feet long. These sucker-rods extend through the tubing to a connection with a

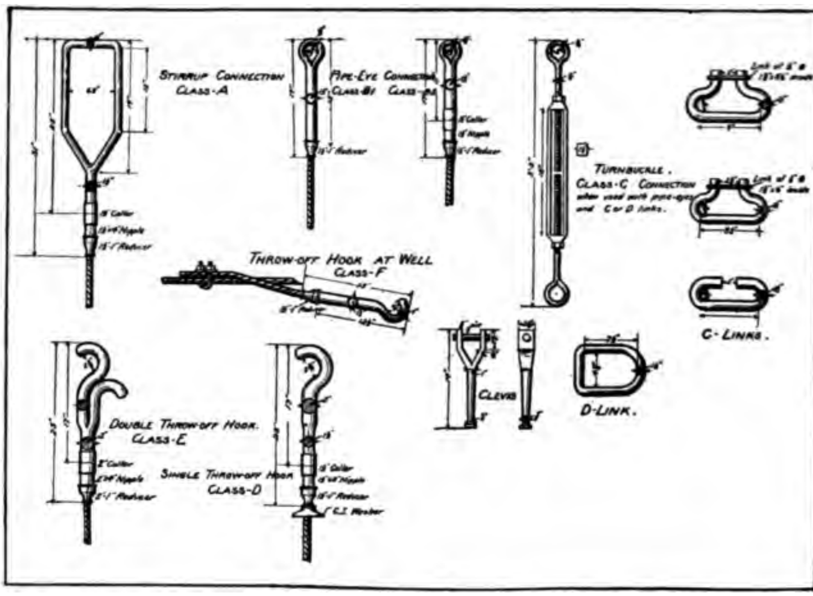


Fig. 98.—Jack line hardware.

polish-rod, which passes through a stuffing-box at the upper end of the tubing and connects with the walking-beam or the pumping-jack, as the case may be.

In considering one complete stroke of the pump, let us assume that the plunger is at its lowest position, with both ball valves closed. When the up-stroke begins, the upper or working-valve remains closed because of the weight of oil above it. The lower or standing-valve opens because of the oil and gas pressure, and the tendency to produce a vacuum within the working-barrel. When

the plunger has reached its highest position, the working-barrel, theoretically, is full of oil, and both valves are momentarily closed. When the down-stroke begins, the lower valve remains closed, while the upper valve is forced open, and the oil passes through it. On the up-stroke following, this oil is raised in the tubing.

In California, the practice is to pump with a 15 to 35-inch stroke, at a rate of 15 to 30 strokes per minute. Using 3-inch tubing and a working-barrel with an internal diameter of 2¾-inches, a 23-inch stroke, and at 20 strokes per minute, the theoretical maximum production is 400 barrels per day.

The gas pressure in a well has the effect of forcing more oil into the working-barrel, and of raising the oil in the tubing. Consequently, a well that produces considerable gas may sometimes produce more oil than the theoretical capacity of the pump. On account of the viscosity of the oil and the sand and other foreign matter pumped with the oil, the working-barrel will not fill with oil. Because of this and also because of slippage, the amount of oil pumped is usually much less than the theoretical capacity of the pump.

The relation between the stroke, frequency, and production of the well is dependent upon the well itself, and will change with the changing conditions within the well ,such as:

1. Gravity of oil.
2. Sand conditions.
4. Amount of water present.
5. Condition of pump and valves.
6. Strength of rods.

This makes it necessary to study each well continually, in order to obtain, not necessarily the maximum production, but the production most consistent with the best results on the entire porperty.

The load is fluctuating, especially in a deep well. When the pumping is done by a steam engine, the latter is run directly on the throttle, and without a governor, so that the fluctuation is greater than with a gas engine, motor, or pumping-jack. A non-uniform stroke with a slower speed on the up-stroke than on the down-stroke, throws less strain on the rods, but a regular movement raises more oil, and makes cleanings less frequent.

Cleaning or "pulling" a well must be done at regular intervals in order to arrest the decline of production, and to replace worn-

out parts in the pump. It is seldom that more than 10 h. p. is required for pumping a well, even on the beam, while about 20 h. p. is needed for pulling the pump and rods, and 25 to 30 h. p. for pulling tubing.

A central-power and jack-pumping plant may be divided into three parts, the central power plant, the transmission lines, and the pumping-jack at the well.

The central-power plant.—Steam power has been used, but either the gas engine or the electric motor is now preferred. Where the wells on the property produce enough gas to run the plant, as is usually the case, the gas engine is generally chosen.

The push-and-pull system already described is used in a number of cases although modified considerably from the earlier installations. A single-disk power can handle from 6 to 20 wells, with depths ranging from 1,000 to 2,000 feet, depending upon the gravity of the oil. A double-disk power can handle from 14 to 25 wells, the depths ranging from 1,600 to 2,500 feet. In general this type of power cannot handle as many wells as the eccentric system.

In the eccentric system there is a pull on the up-stroke of the plunger at the well, and no push on the down-stroke. The down-stroke is caused by the weight of the column of oil on the plunger and the weight of the sucker rods, assisted by any counter-balanced weight-boxes that may be necessary. There are two types, the band-wheel type and the geared-wheel type.

The band-wheel is placed with the shaft vertical, and is driven by a belt from the prime-mover, which is given a quarter-turn by an idler (See Fig. 106). The eccentrics that give the required motion to the rods leading to the wells are fixed on the shaft of the band-wheel. The band-wheel may be made of either steel or wood. The heaviest type of steel band-wheel is designed to handle forty 1500-foot, twenty 2500-foot, or fifteen 3000-foot wells. Geared wheels are usually designed for lighter service than band-wheels. They are provided with one, two, or three eccentrics, and are usually mounted in an iron frame.

The prime mover, if a motor, is generally connected to a counter-shaft by a belt or chain-drive, and thence to the pumping power by a quarter-turn belt over an idler or belt-tightener. By varying the size of the pulleys on the counter-shaft and the speed of the motor or the gas engine, the desired number of strokes per minute

is obtained at the pumping power. The counter-shaft should have a friction clutch for starting wells after the prime-mover has been brought to a regular speed. In case a motor is the prime-mover, a controller and starting rheostat can be used.

The counter-shaft pulleys may be designed by the following formula:

$$\frac{brn}{Ra} = N$$

Where b equals radius of small counter-shaft pulley.
a equals radius of large counter-shaft pulley.
n equals speed of motor, revolutions per minute.
r equals radius of motor-pulley.
R equals radius of band-wheel.
N equals speed of band-wheel or number of strokes per minute.

Assuming that b = 10 inches, n = 865, R = 108, N = 18 and

$$\frac{10 \times 5 \times 865}{108 \times 18} = 22.2 \text{ inch, radius of counter-shaft pulley.}$$

The belt or chain-drive between the prime-mover and the counter-shaft causes little trouble. It is the main belt between the counter-shaft and the band-wheel that should receive the most attention and study. Of rubber belts, a 12-inch, 6-ply rubber belt has been found to give the best service; prepared canvas belts are also being used with gratifying results. Foundations for both prime-mover and pumping power should be of concrete. Not more than 2½ h. p. is needed for pumping each well connected with the central power.

Transmission lines.—While some wooden shackle-rods are still in use, steel rods or cables are preferred. Where new material must be bought in either case, rods are cheaper than cable. Usually there is, however, a lot of old drilling cable around a property that can be used, and this cable, which has had the "stretch" taken out of it, is even better than new cable. On the other hand, old sucker-rods can sometimes be used. Irrespective of cost, rods have the disadvantage of crystallizing and breaking and are not so suitable as cable where a long stroke and a fast motion is required. On the other hand, rods last longer than cable and are better for long lines, although it is advisable in such lines to insert stretches of cable about 100 yards long in all at intervals in order to "take up the pound."

Fig. 98 shows the line-hardware required for a jack-pumping

system. If rods are used instead of cable and the vibration in the line is great, some modification in the connection between the piece of hardware and the line may be required, as the vibration is likely to crystallize the connection. The cable or rods are usually babbitted into the connection.

Line structures.—While the design of the power-end and the

Fig. 99.—Views of shaft-driven pumping powers as used in California. Note jack lines made of steel cable instead of steel rods, which are used universally in Gulf Coast fields.

pumping-end is left mainly to the oil well supply companies, the design and construction of the line structures is usually done by the oil companies themselves. Consequently there is a considerable variation in design, and only what seems to be the preferred practice will be described in this article.

Hold-up posts.—Should be placed at approximately 25-foot intervals and buried 4 feet in the ground. They should be of 4x4-inch timber, the average length being from 5 to 10 feet, according to the

Fig. 100a.—Pendulum type multiplier

Fig. 100b.—Rocker type multiplier

topography. Oregon pine, redwood, or cedar may be used. If Oregon pine is chosen, oil-sand, or earth mixed with oil should be placed around the posts to help prevent decay. All posts should be painted with oil once or twice a year. The shackle-line passes through a slot in the upper end of the post. This slot should be kept greased. Near the power-head, where there is considerable

"side-sweep" to the line ,it should be boxed in at the top of the post instead of running through a groove.

Throw-offs.—It is often desirable to discontinue pumping a well for a time. This is done by means of a "throw-off" at the end of the power-pull rod. The most satisfactory type is shown in Fig. 102-c. A small hook is also used at the well to keep the line taut when disconnected from the pumping-jack.

Bill of Material for 'Throw-Off'

Lumber		
One 2 by 12-inch by 8-foot redwood post	$0.64	
Two 6 by 8-inch by 5-foot cedar		
One 2 by 8-inch by 2-foot cedar		
One 4 by 4-inch by 20-foot cedar	2.80	
One 6 by 8-inch by 8-foot Oregon pine	1.12	
One 2 by 8 by 24-inch hardwood	0.60	
		$ 5.16
Hardware		
One ½ by 6-inch machine bolt	$0.03	
Two ½-inch cut washers	0.01	
One 2-inch single throw-off hook, complete	2.45	
One 1-inch cast-iron washer	0.08	
		$ 2.57
Total material		7.73
Labor		5.25
Total		$12.98

Redwood and cedar are assumed to cost $40; pine, $35; and hardwood, $225 per M. B. M. In this and the following tables the cost data should be regarded as only approximate. The lumber will weight about 485 pounds and the hardware about 30 pounds. At the well there should be a single throw-off hook complete, costing $1.05, and two wire-line clamps, costing $0.50, or $1.55 in all.

Multipliers are used for the following purposes:

1. To increase or decrease length of stroke between the power and the well.

2. To increase length of stroke to compensate for the amount lost in sagging lines.

3. To change direction of the shackle-lines in a vertical plane.

4. To aid in crossing over or under a road. There are two types, the pendulum or surface type, shown in Fig. 100-A and the rocker or under ground type shown in Fig. 100-B. In the rocker-multipliers, the swingpost casting should be placed from 12 to 18 inches below the surface. It should be boxed and the boxing banked with oil sand. While it is advisable to have as long a leverarm as possible, the swing-post castings should not be set too

Fig. 101a.—Hold-up type of rocker

Fig. 101b.—Hold-up type of pendulum

deep ,as this makes either oiling or repairs difficult. As it is best to keep the lines as near the ground as possible, this type of multiplier is best adapted to rough country, and even there it will generally be better to use a pendulum-multiplier. As will be seen from the bills of material below, the pendulum-multiplier is the cheapest, and it should be used wherever the conditions will permit.

Bill of Material for Rocker-Type Multiplier

Lumber

Four 2 by 12-inch by 5-foot, redwood	$1.60	
Two 6 by 8-inch by 5-foot, cedar	1.60	
Eight 2 by 12-inch by 2-foot, Oregon pine		
One 6 by 8-inch by 8-foot, Oregon pine	2.24	
		$ 5.44

Hardware

Two 1½-inch stirrups, complete	$4.70	
Two stirrup-plates	0.60	
Four ¾ by 10-inch hook-bolts	0.60	
One set swing-post castings, complete	12.00	
Eight ¾ by 8-inch machine-bolts	0.32	
Eight ¾-inch cut washers	0.04	
		$18.26
Total material		23.70
Labor		5.50
Total		$29.20

The lumber will weight 340 pounds, and the hardware 255 pounds, a total of 595 pounds.

Bill of Material for Pendulum-Type Multiplier

Lumber

Two 2 by 12-inch by 4-foot, redwood	$0.64	
Three 6 by 8-inch by 4-foot, cedar		
One 2 by 8-inch by 4-foot cedar	3.40	
Two 4 by 4-inch by 12-foot, cedar		
Two 6 by 8-inch by 8-foot, Oregon pine		
One 6 by 8-inch by 7-foot, Oregon pine		
Four 2 by 6-inch by 4-foot, Oregon pine		
One 2 by 12 by 18-inch, Oregon pine	3.89	
		$ 7.93

Hardware

Two 1½-inch stirrups, complete	$4.70	
Two stirrup-plates	0.60	
Three ½ by 9-inch machine-bolts	0.12	
Four ¾ by 10-inch hook-bolts	0.60	
Four ¾-inch cut-washers	0.02	
Six ½-inch cut-washers	0.02	
One 1½ by 16-inch nipple	Nominal	
		$ 6.06
Total material		13.99
Labor		6.25
Total cost		$20.24

For an increase in stroke the power-line is the closest to the swing-post casting, and for a decrease in stroke, the well-line is the closest. In both types of multiplier, the outer stirrup should be kept 6 inches from the end of the post, and the inner stirrup moved for regulation.

Assuming a shackle-line consisting of rods with consequently no stretch, let us find the arrangement in order to increase the stroke from 18 inches at the power to 24 inches at the well, using J & H jack, which does not permit multiplication at the well.

Fig. 101-C—Pendulum—Hold-down Type.

Fig. 102-E—Hooking Off.

This would be done by two multipliers along the line, or a multiplier and counterbalance that will multiply, allowing 3 inches to each. If a rocker-multiplier is used to change from 18 to 21 inches, the distance between the stirrups is found to be 13 inches. Using a pendulum-multiplier for the change from 21 to 24 inches, the distance is 8½ inches.

For road-crossings, an overhead structure with two "hold-up"

posts can be used provided the line is high enough. Other overhead crossings are unsatisfactory. For an underground crossing, a pendulum-multiplier makes the best structure. The bill of material is the same as for a multiplier, with the addition of a joint of "junk" casing to go under the road.

Rockers and pendulums are used to change the direction of the line in a vertical plane, when a multiplier is not needed. The feature of this type of construction is the loose block of wood, or "loose-head," to which the line is fastened. It works freely with a rotary motion in a vertical plane, and tends to take up any inequalities or vibration in the line.

Like the rocker-multiplier, the plain rocker is to be avoided whenever possible, the pendulum being the preferred type of structure. The lumber needed for the rocker is the same as for the rocker-multiplier. The hardware is as follows:

Two ½ by 2 by 24-inch straps	$ 1.00	
Two ¼ by 10-inch hook-bolts	0.30	
Eleven ¾ by 8-inch machine-bolts	0.75	
Six ¾ by 8-inch cut washers	.03	
One Set swing post castings	12.00	
		$14.08
Total cost material		14.08
Labor		4.50
Total, labor and material		$24.02

The pendulum is constructed like a pendulum-multiplier, except that the back-braces are omitted.

A **"butterfly" or angle** may be used for the following purposes:

1. To change the direction of the line in a horizontal plane in order to get around an obstacle, or to run the line from the power in some other direction than that of the well in order to balance the power properly.
2. To furnish an emergency connection between a well-motor and the jack-pump.

The line should enter and leave the butterfly horizontally. This can be accomplished by the use of either a rocker or a pendulum.

Following is a bill of material for a butterfly:

Lumber

One 2 by 12-inch by 10-foot, redwood		
One 2 by 12-inch by 12-foot, redwood	$1.76	
One 6 by 8-inch by 12-foot, cedar		
One 12 by 12-inch by 6-foot, cedar		
One 6 by 8-inch by 3-foot, cedar		
Two 4 by 4-inch by 12-foot, cedar		
One 2 by 12-inch by 4-foot, cedar	6.88	
One 6 by 12-inch by 18-foot, Oregon pine		
One 6 by 8-inch by 14-foot, Oregon pine		
Two 4 by 4-inch by 14-foot, Oregon pine		
Two 4 by 4-inch by 10-foot, Oregon pine		
Two 2 by 6-inch by 12-foot, Oregon pine	8.68	
		$17.32

Hardware

Two 1½-inch stirrups, complete	$4.70	
One set swing-post castings, complete	12.00	
Two stirrup-plates	0.60	
One 1-inch by 12-foot double-end bolt	1.50	
One 1-inch by 4-foot 3-inch double-end bolt	0.60	
One 1-inch by 7-foot 3-inch double-end bolt	1.00	
One ¾ by 15-inch machine-bolt	0.15	
One ¾ by 19-inch machine-bolt	0.20	
Four ¾ by 14-inch machine-bolts	0.50	
Four ¾ by 8-inch machine-bolts	0.20	
Two ¾ by 9-inch machine-bolts	0.12	
Four ¾ by 10-inch hook-olts	0.60	
Eight ½ by 9-inch machine-bolts	0.40	
Six 1-inch cast washers	0.33	
Four ¾-inch cast washers	0.10	
Thirty-two ¾-inch cut washers	0.14	
Sixteen ½-inch cut washers	0.05	
		$23.19
Total cost of material		40.51
Labor		22.50
Total cost		$63.01

The total weight of lumber is 1200 pounds and or hardware, 400 pounds, making 1600 pounds in all. A lighter butterfly can be constructed for places where the service is not so exacting at a cost of $57.62.

Where the angle of deflection is small and the service not exacting, a "hold-out swing" or horizontal rocker may be used. A "hold-in swing" as its name implies is the reverse of a "hold-out swing." It is not so satisfactory, and should be used only where

a "hold-out swing" is not practical. The bill of material for "hold-out swing" is as follows:

Lumber

One 2 by 12-inch by 10-foot, redwood	
One 2 by 12-inch by 12-foot, redwood	$1.76
One 12 by 12-inch by 6-foot, cedar	
One 2 by 8-inch by 4-foot, cedar	
One 6 by 8-inch by 3-foot, cedar	
One 6 by 8-inch by 6-foot, cedar	
Two 4 by 4-inch by 11-foot, cedar	5.76
One 6 by 8-inch by 16-foot, Oregon pine	
One 6 by 8-inch by 10-foot, Oregon pine	
One 4 by 4-inch by 16-foot, Oregon pine	4.41
	$11.93

Fig. 102a.—Butterfly

Fig. 102b.—Beam

Fig. 102c.—Throw-off

Fig. 102d.—Hooked off

Hardware

One set swing-post castings	$12.00
One ¾ by 15-inch machine-bolt	0.15
One ¾ by 19-inch machine-bolt	0.20
Five ¾ by 8-inch machine-bolts	0.20
Two ¾ by 9-inch machine-bolts	0.12
Two ½ by 9-inch machine-bolts	0.10
Two ¾ by 10-inch hook-bolts	0.30
Twenty-two ¾-inch cut washers	0.10
Four ½-inch cut washers	0.01

Hardware—Continued

Four ¾-inch cast washers	$0.10	
Two ½ by 12 by 24-inch iron straps	1.00	
		$14.28
Total material		26.21
Total labor		20.00
Total cost		$46.21

A beam is used for the rare occasions when the proper balancing of the power requires that the direction of the line be changed through an angle of 180 degrees. The wear on the swing-post casting is heavy, and breakages are frequent.

A counter-balance is used to help balance the well loads about the central power plant. It can also be used as a multiplier to increase or decrease the length of the stroke. The load in the weight-box can be varied to suit the conditions. This is particularly necessary on a property where new wells are being added to the load on the plant, requiring a re-balancing of the system. The line is connected to the counter-balance of the system. The line is connected to the counter-balance by the following hardware, in the order named: pipe-eye, C-link, turnbuckle, C-link, pipe-eye and stirrup. The bill of material is as follows:

Lumber

One 8 by 8-inch by 16-foot, cedar	$ 3.44	
Seven 2 by 12-inch by 12-foot, Oregon pine		
Two 6 by 8-inch by 10-foot, Oregon pine		
One 6 by 8-inch by 5-foot, Oregon pine		
One 6 by 8-inch by 8-foot, Oregon pine		
One 6 by 6-inch by 2-foot, Oregon pine		
Two 2 by 6-inch by 14-foot, Oregon pine	11.69	
		$15.13

Hardware

Two sets swing-post castings, complete	$24.00	
Two 1½-inch stirrups	4.70	
Two stirrup-plates	0.60	
One turnbuckle	4.25	
Two C-links, with link	2.30	
Two 1½-inch pipe-eye connection	2.50	
Twelve ¾ by 8-inch machine-bolts	0.50	
Six ¾ by 15-inch machine-bolts	0.84	
Four 1-inch cast washers	0.22	
Forty-four ¾-inch cut washers	0.22	
		$43.23
Total material		58.36
Total labor		17.50
Total		$75.86

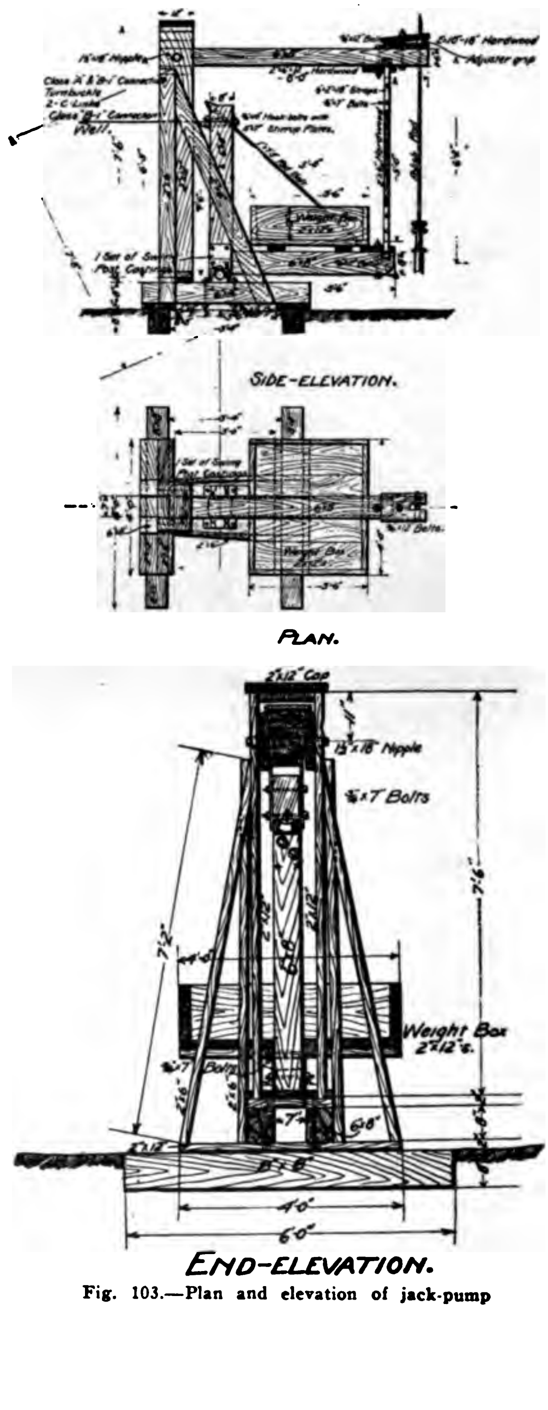


Fig. 103.—Plan and elevation of jack-pump

Jack-pumps (Fig. 103) are used to pump the oil from gathering stations to the central shipping tanks. They are also used sometimes at the well as tail-pumps to transfer the oil from the well to the gathering station. The weight-box is required in order to produce the downward stroke. The type of pump works upon the principle of the Oklahoma jack. A turnbuckle connection, similar to that used with the counter-balance weight, is desirable to take the slack out of the line. The capacity of the pump should be considerably more than the normal production of the wells served by the gathering station. A bill of materials for the pump is as follows:

Lumber

One 8 by 8-inch by 16-foot, cedar	$3.44	
One 6 by 8-inch by 10-foot, Oregon pine		
One 6 by 8-inch by 8-foot, Oregon pine		
One 6 by 8-inch by 12-foot, Oregon pine		
Two 2 by 12-inch by 12-foot, Oregon pine		
One 2 by 12-inch by 16-foot, Oregon pine		
One 2 by 12-inch by 8-foot, Oregon pine		
Two 2 by 6-inch by 16-foot, Oregon pine		
One 2 by 6-inch by 8-foot, Oregon pine	8.96	
One 2 by 6-inch by 5-foot, hardwood		
One 2 by 10-inch by 5-foot, hardwood	1.80	
		$14.20

Hardware

One set swing-post castings, complete	$12.00	
One 1-inch by 7-foot 3-inch double-end bolt	1.20	
One 1½-inch stirrup	2.35	
One stirrup-plate	0.30	
One turnbuckle	4.25	
Two C-links with link	2.30	
Two 1½-inch pipe-eye connections	2.50	
Two ¾ by 10-inch hook-bolts	0.60	
Three ¾ by 13-inch machine-bolts	0.36	
Eight ¼ by 8-inch machine-bolts	0.36	
Four ⅜ by 10-inch machine-bolts	0.40	
One 1¼ by 18-inch nipple	Nominal	
Four ½ by 2 by 18-inch straps	1.80	
One 4-inch plunger-pump, complete with working-barrel stuffing-box, etc. (Not charged against jack-pump)		
		$28.42
Total material		42.62
Total labor		20.00
Total cost		$62.62

The weight of lumber is 880 pounds, and of hardware not counting the pump, 300 pounds, or 1180 pounds in all.

Structures at the well.—The pumping-jack is the device at the well that transfers the horizontal reciprocating motion given by the central power to the transmission lines, to the vertical reciprocating motion required by the sucker-rods to actuate the plunger-pump. There are two principal types of steel jacks, the Oklahoma jack shown in Fig. 104, and the Jones & Hammond or J & H jack, shown in Fig. 105. Wooden jacks are used sometimes.

The Oklahoma jack is a combination triangle and walking-beam.

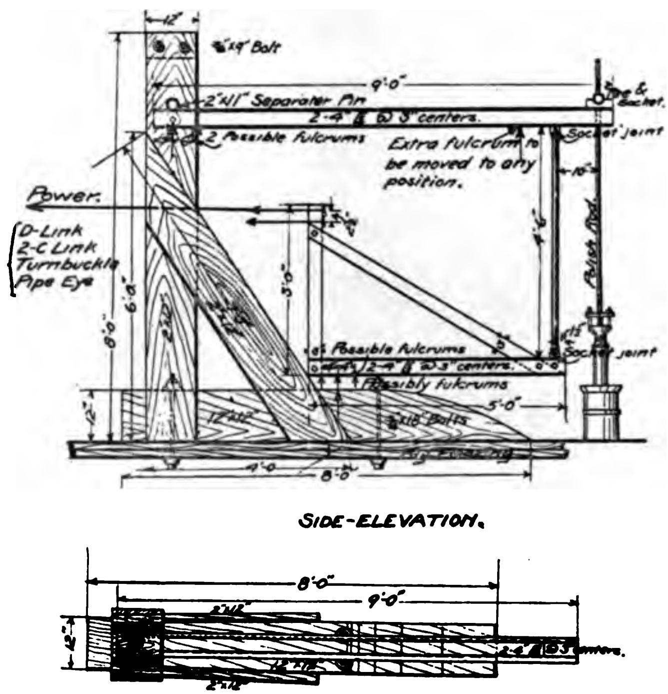


Fig. 104.—Oklahoma pumping jack

The jack is made of structural steel, and should be mounted on a rigid supporting structure of Oregon pine. The lower fulcrum is furnished with the jack, and is bolted to a 12 by 12-inch timber. The length of stroke can be regulated at the well by changing the different fulcrums. This facilitates experimenting on the length of stroke required for best results at the well, and also reduces the number of multipliers needed on the line.

It is evident that there are an infinite number of combinations for different lengths of stroke, depending upon the choice of fulcrums and on the arrangement of the supporting structure itself. The jack will work the easiest for long lever-arms on the walking beam, and short distances between the pitman and the polished rod. Where—

X=ratio between length of stroke at polish-rod to length of stroke at shackle-line.

A=triangle arm, vertical leg.

B=triangle arm, horizontal leg.

C=pitman-arm.

D=pumping-arm, then $X = \dfrac{BD}{AC}$

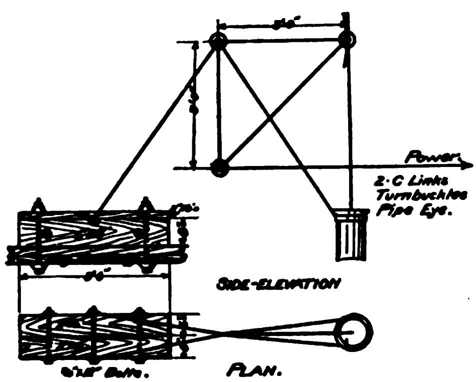


Fig. 105.—Jones & Hammond pumping jack

The bill of material for an Oklahoma jack is as follows:

One 12 by 12-inch by 8-foot, Oregon pine....................		
Two 2 by 12-inch by 16-foot, Oregon pine....................		
One 6 by 6-inch by 12-foot, Oregon pine.....................	$5.70	
		$ 5.70

Pumping-Jack

One heavy California style Oklahoma jack................	$42.00	
One Oklahoma polish-rod clamp...........................	2.75	
		$44.75

Bolts and Washers

Four ¾ by 19-inch machine-bolts	$0.75	
Two ¾ by 11-inch machine-bolts	0.16	
Eight ¾-inch cast washers	0.20	
Four ¾-inch cut washers	0.02	
		$ 1.13

Connections

One D-link	0.90	
Two C-links, with link	2.30	
One turnbuckle	4.25	
One pipe-eye connection	1.15	
		$ 8.70
Total material		$60.28
Total labor		5.50
Total cost		$65.78

The total weight is 1102 pounds.

The Jones & Hammond jack transfers the horizontal to vertical motion acting merely as a triangle. The jack is built of tubular shapes. One of the supporting legs clamps around the casing-head, and the other is bolted to the derrick-floor. The connection may be either upper or lower, depending upon how it is desired to bring the shackle-line to the well. The lower connection is better because it is the stiffer. The bill of material is as follows:

Lumber

Two 6 by 8-inch by 4-foot, Oregon pine		
Two 2 by 6-inch by 4-foot, Oregon pine	$1.40	
		$ 1.40

Pumping-Jack

One Jones & Hammond No. 3 jack, complete	$36.60	
		$38.60

Bolts and Washers

Four ¾ by 18-inch machine-bolts	$0.75	
Three ¾ by 13-inch machine-bolts	0.36	
Eight ¾-inch cast washers	0.20	
Six ¾-inch cut washers	0.03	
		$ 1.34

Connections

Two C-links with link	$2.30	
One turnbuckle	4.25	
One pipe-eye	1.25	
		$ 7.80
Total material		$49.14
Total labor		2.00
Total cost		$51.14

The total weight is 633 pounds.

The advantage of the Oklahoma jack are compared with the J & H jack are as follows:

1. It is easy to disconnect and lay aside during "pulling" operations.

2. When the well "sands up," which is always on the up-stroke, the pack falls apart automatically, and there is no pounding.

3. The stroke can be regulated at the well.

On the other hand the J & H jack costs less to install and does not pull as hard as the Oklahoma jack. Also because the motion of the polish-rod is vertical, there is less wear on the suffing-box. However, the Oklahoma jack has been found to be the best for heavy service.

Foundations for line and well-structures.—Oregon pine is not recommended for this work. In case it is used, all parts in contact with earth should be painted with oil, and buried in oil sand or else earth moistened with oil. Redwood may be used for the small foundation sills of 2 by 12-inch timber. Cedar should be used for the larger timbers, and is really more economical than Oregon pine, because it does not require painting or other treatment. In some parts of the structures, such as the vertical posts, cedar may not be strong enough, and Oregon pine should be used in its place.

Length and frequency of stroke.—The "pound" in shackle-lines results from the downward motion of the plunger of the pump continuing after the line begins the back stroke. In order to minimize this effect, the shortest and slowest stroke that will pump the well to its full capacity should be used. Decreasing the length of stroke also decreases the wear of the polish-rod against the stuffing-box. When the well is pumped too fast for its production the flow of the oil will be intermittent and the oil will rise only part way in the pump barrel, making the plunger pound against the oil and gas cushion on the down stroke. On the Nevada division of the General Petroleum Corporation, the frequency of stroke used is from 14½ to 16 per minute. On the Belridge division, 16 strokes per minute is the rule. The length of stroke on these properties varies from 14 to 24 inches, and is based on a study of the individual wells.

The Nevada division of the General Petroleum Corporation is on "Twenty-five Hill," in the Midway field, near Taft. The jack-pumping plant was placed in operation in April 1915. Before that

time the wells had been pumped on the beam by individual motors. This was the first large plant to be constructed in the Midway field, and the experience in the construction of this plant proved to be of considerable value in the construction of the Belridge plant, which was completed in July, 1915. This is in the Belridge field, about 12 miles from McKittrick. The General Petroleum Corporation has a third plant now under construction at Lost Hills. The general characteristics of the three plants is shown in the accompanying table:

	Nevada division	Belridge division	Lost Hills division
Topography	Rough	Smooth	Smooth
Number of wells	46	21	50
Number of jack-pumps	2	2	
Number of central plants	3	1	3
Age of wells, years	4-7	3-5	1-6
Average depth of wells, feet	1150	800	1200
Average depth to fluid, feet	1150	720	
Gas	*	†	†
Sand, per cent	0.0 to 1 8	0 1 to 1.8	Small
Average gravity, Baume	14	14 to 26	26 to 35
average production, barrels per day	30	15 to 220	50
Length of lines, feet	28,000	28,000	44,000
Throw-offs	48	23	50
Posts	928	1080	1760
Multipliers	96	16	130
Rockers and pendulums	44		2
Angles	10	5	10
Hold-outs		1	4
Hold-ins		1	
Counter-balances		9	

*Very little. †Good pressure.

On both the Nevada and Belridge divisions, there was a considerable reduction in sand trouble after the plants were completed. Power consumption has also been reduced considerably as is shown by the following data. Power No. 1 at the Nevada division serves 18 wells and one jack-pump. A test soon after the plant was placed in operation showed a consumption of 2.2 h. p. per well, and a cost for power of $0.394 per well per day, current costing $0.01 per kilowatt-hour. Power No. 2 serves 18 wells. The consumption was 2.6 h. p. per well, and the cost $0.467 per well per day. Power No. 3 serves 10 wells and a jack-pump. The lines are long and the "power" not well balanced, so the consumption of power is high, 3.5 h. p. per well, and the cost is $0.625 per well per day. The average for all three powers was 2.45 h. p. per well, and $0.438 per well per

day for pumping alone. For pumping and pulling combined, the figures were 2.56 h. p. and $0.458. When the wells were pumped on the beam, the cost of power per well per day was $1.05 and the average horse-power per well, 5.85, showing a saving of 56 per cent by the use of a jack-pumping system. Since this test the consumption of power has been reduced considerably. Records for six months, covering both summer and winter conditions, show an average cost of power of $0.018 per barrel pumped. On the Belridge division, the average consumption of power is 1.59 kilowatt-hours per barrel pumped. In general it has been found in California that the average consumption of power per well per day is from 15 to 40 kilowatt-hours and per barrel pumped, 1.5 to 2.5 kilowatt-hours.

A jack-pumping system operated by gas-engines or electric motors will show a large reduction in cost over pumping the same wells on the beam by steam. Besides the saving in power there is also a considerable reduction in labor costs. In general the construction of a jack-pumping system will reduce the total pumping cost at least 50 per cent, as compared with individual installations at the well.

A portable outfit for pulling the wells is being used successfully in the Kern River Field. This releases the equipment at the wells which is lying idle a larger part of the time, such as the motor, gas engine, or steam engine, the rig irons, and all the lumber except that which is in the derrick.

Balancing the load on the central power.—Knowing the depth of each well, the size of the tubing and sucker-rods, and the gravity of the liquid to be pumped, the weight upon the plunger of the pump in each well can be computed. This weight must be lifted through a distance corresponding to the length of stroke of the plunger.

Assume that there is no motion in the system. This weight upon the plunger becomes a static load, causing a vertical force to be changed by means of the pumping-jack to a horizontal force. The point where the resultant of all the horizontal forces in the plant is zero can be determined by trial. This will determine a tentative position for the central plant.

The moment the central power is set in motion, friction increases the load in one direction and decreases it in the opposite direction. The components of this friction are as follows:

1. Friction at the pump. This may be estimated from previous knowledge of the well, whether it has been a hard or an easy pumper.

2. Friction at the pumping-jack. This may be estimated by assuming a friction factor.

3. Friction in the transmission line. This may also be estimated by asuming as friction factor.

Assuming that the central-power has a single eccentric disk, the frictional forces may be resolved along two co-ordinate axes and three or more points obtained by trial where the resultant of the forces is approximately zero. The power plant should be placed at the most convienent position with reference to these points. The same method may be used with a double-disk power, since with the proper connection of the lines to the upper and lower eccentrics, all the friction forces will nearly balance each other, leaving only minor adjustments to be made after the plant was put in operation.

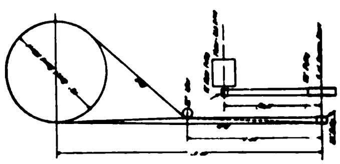


Fig. 106.—General lay-out of machinery for central power plant

In general, when the topography is rough and the wells are in a compact group, it will be found adivsable to choose a suitable position for the central plant as near the geographical center of the wells as possible. Graphical methods will be found of value in determining the direction of the transmission lines.

Where the wells are scattered, the point of zero resultant should first be determined, and the plant placed at the nearest suitable point. As before, graphical methods will be of assistance in designing the transmission system.

Where the topography is smooth and the wells are in a compact group the central plant should be placed as near as possible to the geographical centre of the group. Where the wells are scattered, graphical methods will be of use in determining the point of zero resultant.

In any case, some adjustment will be required after the plant is placed in operation. Where a motor is used for the power, the balancing of the well-loads may be done with a portable ammeter placed on the motor-circuit. The position of the power-head for

maximum load is noted and the line-connections adjusted until the ammeter-dial maintains a constant position or varies at a uniform rate. Where a gas-engine is used, the final balancing is a matter of "cut-and-try."

An approximate estimate has been made of the cost of construction of a jack-pumping system. A fully developed oil-property with an area of 80 acres, ½ mile long and ¼ mile wide has been assumed. Smooth topography and three rows of seven wells each are also assumed, with a central power-plant near the centre of the property. It is also assumed that the wells were being pumped "on the beam" by individual motors, and that these motors will be retained and used for cleaning operations.

Central plant	Labor	Material	Total
Building, 24x70 feet, corrugated galvanized iron, 8-foot eaves	$110	$ 430	$ 540
One 40-h. p. gas engine, complete with clutch, governor, fittings and starter	100	1,380	1,480
National underpull power, with belt, belt-tightener, pull-rods, couplings and pins	80	1,123	1,203
Concrete foundation for power and gas engine, 1:3:5 mixture, 15 cy. yd	175	70	245
Total, central plant			$3,468
700 4x4-inch x 6-foot posts	224	350	514
Lines, 19,000 feet of old 1-inch cable, no charge for material	....	400	400
23 throw-off posts at $13	....	......	299
21 pendulum-multipliers, at $20.25	....	......	425
3 pendulums at $13.20	....	......	40
4 heavy butterflys, at $63	....	......	252
2 hold-out swings, at $46.20	....	......	92
6 counter-balance weights at $75.85	....	......	455
2 jack-pumps at $62.60	....	......	125
21 Oklahoma jacks, complete, at $65.78	....	......	1,383
Total			$7,553

Including hauling, the total cost would be about $8000 or approximately $380 per well served. The total weight including materials for the concrete foundation, would be about 212,000 pounds.

New type power recently designed by The Texas Company.— This power resembles somewhat the well known rotary drilling machine, having a revolving table driven by a master gear attached thereto. This table revolves around a column which is cast integral with a large base plate acting as the foundation. Roller

bearings as used under the table of a rotary have been eliminated and a plain flat surface is used, similar in construction to that of the machine shop boring mill in which two flat iron surfaces are used to carry the weight. The old style pumping power has been eliminated and this machine is directly connected to an oil engine, there being sufficient reduction between the master gear and pinion to allow the oil engine to run at its most efficient speed, aiming to operate the power between 25 and 30 revolutions per minute. A double crank arrangement placed on the table top re-

Fig. 106A.—Band wheel pumping power

places the old method of eccentric drive and gives considerably greater stroke to the pump. This double crank is made of one solid steel casting while the rings to which the shackle rods are connected are babbitted and are adjustable by the removal of shims. Provision is made for pumping 32 wells, and if properly located with relation to these wells, an oil engine of 55 h. p. will operate this power satisfactorily.

The Marietta Process for Increasing Production of Oil Wells

The Smith-Dunn or Marietta process for increasing the production of a well in an old field by forcing air down one well in a group was developed at Marietta, Ohio, and is now used extensively in the Appalachian fields, and also to some extent in the Oklahoma fields. It has been tried in California by the Montebello Oil Company, in Ventura Couny, but was abandoned. Where it has been successful the average increase in production has been 300 per cent, and in some cases as great as 900 per cent. It should, however, be

stated that the average production of wells in the districts where the process has been used is less than one barrel per day.

Where the method is used, one producing well in a group is selected as an air well. Best results are usually obtained when there is one air well to three pumping wells. The air is forced down the air well through a string of tubing with a packer at the end. It is important that the air does not have access to the stratum above the oil sand. The pressure used is about 150 pounds per square inch, varying somewhat with local conditions. From 5,000 to 20,000 cubic feet of free air per well per day is needed. From 1½ to 2 horse-power per well is required. The pumping wells are operated as usual, either by jacks or on the beam.

The air takes up the volatile constituents of the oil in the form of vapor and is caught and used in gas engines required to operate the property. It is possible that this air might be used successfully for making casinghead gasoline.

The first effect of the use of this process is an increase of gas from the pumping wells. Then follows an increase in water, and finally an increase in the oil production. Frequently the full effects of the oil production will not be seen for several months. There is also an increase in the amount of sand.

The cost of installation of this process is from $100.00 to $150.00 per well. There is also an increased cost of maintenance of from 25 to 50 per cent. This process is sometimes used in connection with vacuum pumps on the producing wells, but since the limit of vacuum is about 10 pounds, most operators prefer to carry more pressure on the air compressors.

As has already been stated, this process has been successful on wells of very small production, and whether or not it would be of value for Californian conditions remains to be demonstrated.

Extinguishing Burning Oil Wells[1]

Oil well fires are often much more difficult to overcome than gas well fires, because the well may be producing in such large quantities that the oil is not all consumed in one tapering flame, as with gas, but may flow away in a blazing mass for a considerable distance. Also the burning oil soon heats the ground around the

[1]C. P. Bowie in U. S. Bureau of Mines No. 170.

well so hot that no matter how often the fire may be extinguished it will immediately re-ignite.

Thus, no definite rules can be given for combating fires at oil wells, as each burning well presents a problem of its own. The following descriptions of methods that have been successfully used are given, as has been stated, not with the belief that any one of these could be successfully applied to some other fire, although it might be, but with the hope that the ideas presented may, when used singly or in combination, be of service to operators in dealing with such fires in the future.

Methods used on fire at a Texas well.—C. P. Clayton, superintendent of the Producers Oil Company, gives the following account of an oil well fire in the Humble field, Texas, which was extinguished under his supervision in February, 1916.

The well had been flowing for two days and was making about 6000 barrels daily. It was being brought under control at the time the fire occurred, and most of the oil was discharging through a 6-inch flow line extending about 20 feet from the head of the casing. Immediately over the well, about six feet above the derrick floor, oil was discharging through a two-inch opening in a four-inch tool joint at the rate of about 100 barrels per hour. The fire was caused by an electric spark in repairing a broken power line on the derrick floor.

The well was situated in a heavily timbered country, and, as a first precaution, all timber, stumps and other inflammable material were removed from the vicinity. Twenty-nine portable field boilers were then set up, and a network of four-inch and two-inch steam lines laid about the well. Also connections were made to 7 boilers already installed at nearby drilling wells, and 7 two-inch water lines were laid. While this was being done a circular levee about three feet high was thrown up around the well, at a distance of about 50 feet from it. Opposite the flow line a ditch 218 feet long and four feet wide at the top ,tapering to a depth of about four feet, was dug, which opened into a circular ditch of about the same depth, and having for its outer circumference a radius of about 75 feet. This arrangement is shown graphically in Fig. 107. The straight ditch was then covered with corrugated iron, upon which was placed about two feet of earth. A piece of 36-inch smokestack

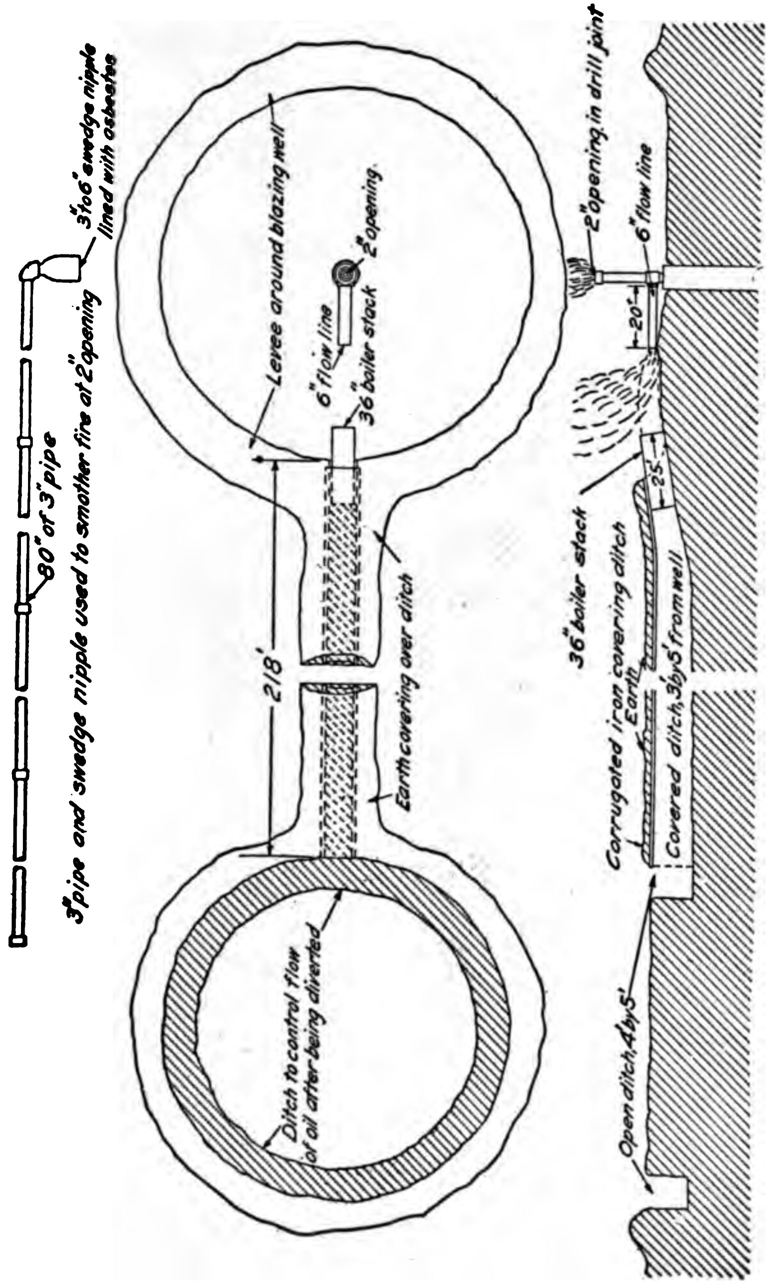


Fig. 107.—Arrangement for extinguishing an oil-well fire by forcing blaze into a boiler stack, used by C. P. Clayton

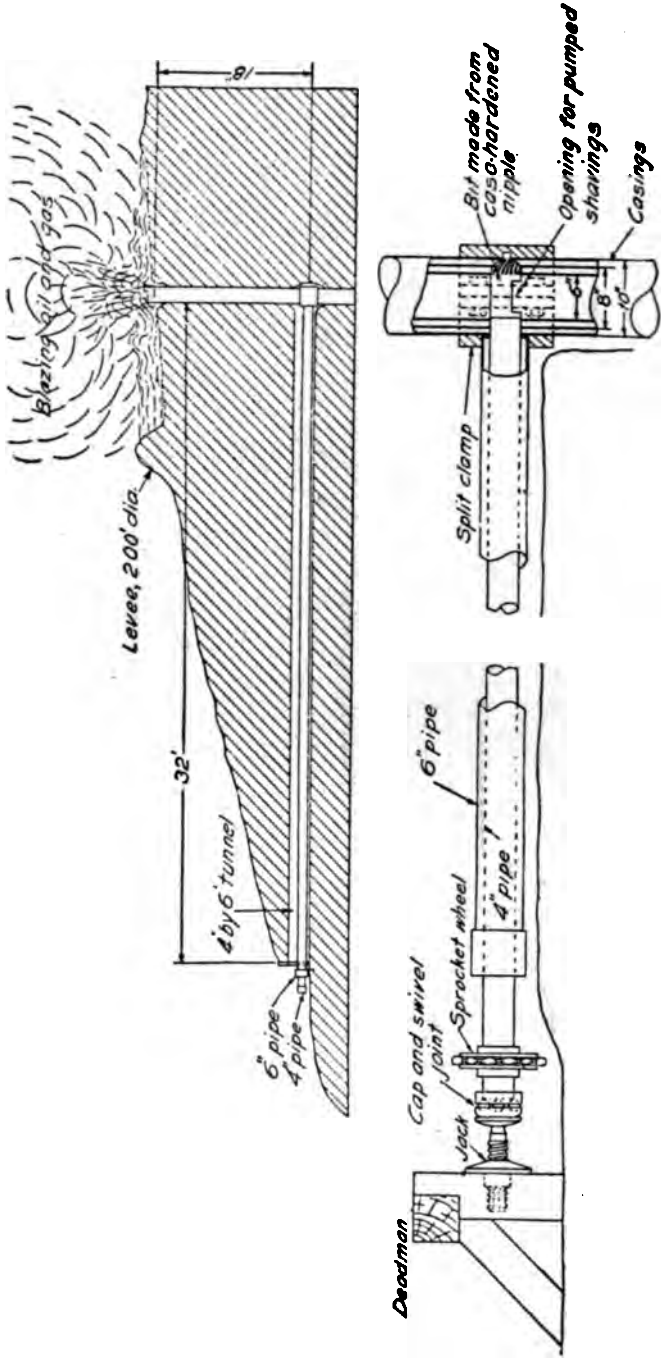


Fig. 108.—Method of extinguishing oil-well fire by shutting off flow, used by C. P. Clayton.

was then placed in the mouth of this ditch and shoved up to within about 25 feet of the end of the flow line.

When all was in readiness, an asbestos-lined swedge nipple about 8 inches in diameter, attached to 80 feet of three-inch pipe, was placed over the spray of burning oil discharging from the tool joint. This was done by men working from behind a corrugated iron shield.

At the second attempt this part of the fire was quenched and the oil discharging at this point, or the greater part of it, was made to flow through the three-inch pipe. Immediately the steam and water was turned on the blaze at the end of the flow line (the men advancing behind shields) in such a manner as to drive the flame into the mouth of the 36-inch stack and extinguish it. The men protected their hands with gunny sacks and asbestos shields, and streams of water were continually sprayed upon them as they advanced. The preparatory work required about 17 hours; the actual quenching of the flames about 15 minutes.

Method used at a fire at a well in Louisiana.—Mr. Clayton also describes a method used by him to extinguish an oil well fire in Caddo Parish, Louisiana, in 1911. This well burned 26 days, 2 hours and 10 minutes, and when the fire had been put out, a gage record showed a production of 48,000 barrels daily. The discharge was so great that the oil was not all consumed until some of it had flowed a distance of more than 100 feet from the well.

Thirty-six boilers were erected and the fire fought with steam for six days, but without success. At the end of this time this method was abandoned and a circular levee about three feet high and 200 feet in diameter was thrown up around the well, which formed a pond of blazing oil in which all the flow was consumed.

The well being on a hillside, a tunnel 4 by 6 feet by 328 feet long was driven (See Fig. 108), striking the outer casing at a point 18 feet below the surface, measured to the center of the face of the tunnel. The well contained three strings of casing, 10-inch, 8-inch and 6-inch. A split clamp was placed around the 10-inch casing, and to this was attached a string of 6-inch pipe extending beyond the mouth of the tunnel. An especially constructed 4-inch bit, shown in Fig. 109, was made from a case-hardened nipple. This bit had in one side a hole 2 inches square and was screwed onto the end of a string of 4-inch pipe; the joints of the pipe after being

screwed tightly together, were also riveted. This string was placed inside the 6-inch pipe and was fitted on the outer end with a cap and a sprocket wheel to which was attached a rotary chain drive. A deadman was set opposite the end of the pipe and a jack set between it and the cap.

The chain drive was then set in motion and a hole drilled through the casings. Careful measurements were kept on the jack as the 4-inch line advanced, so that the opening in the bit would be stopped as nearly as possible in the center of the 6-inch casing. When this point was reached, the bit was turned so that the hole was "looking" down into the well. A circulating pump was connected with the 4-inch pipe and asbestos shavings forced through it under pressure of 1200 pounds per square inch. After this had been done for a few minutes the pipe was to turned that the hole in the bit was on top and the flow of the well was shut off. The oil on the surface, inside the levee, was soon consumed and the fire extinguished from the lack of fuel.

Fig. 109.—Special 4-inch bit made from a case hardened nipple

In discussing this method, Mr. Clayton states that the tunnel, where it intersected the casing, was too near the surface. He thinks the distance should have been at least 30 feet, as several of the men in placing the split clamp were almost overcome by the heat and gas fumes. Also, the tunnel was too small. Had it been 6 feet by 6 feet instead of 4 feet by 6 feet, the labor of driving it and of placing the 6-inch pipe would have been greatly facilitated and the time reduced.

Method used by M. E. Lombardi.—M. E. Lombardi, superintendent of construction of the fuel oil department of the Southern Pacific railroad, describes an oil well fire extinguished under his

direction which occurred in the Midway oil field, California, in 1913.

The well had been drilled by the rotary system and caught fire just after it had unexpectedly started flowing, so the rotary table was still in place. After the floor of the derrick had burned the table crumpled the end of the casing, which extended several feet above the ground, until the table rested on the ground. This formed a baffle and the oil spurted out laterally with such force that before long a crater about 50 feet wide by 40 feet deep was formed.

A large number of field boilers were set up near the well and the usual method of applying steam and water resorted to. The fire was repeatedly extinguished, but the sides of the crater had become so hot that the gas and the oil reignited as soon as the blanket of steam lifted.

The well was on a hillside and the soil was a heavy clay. A pit about 50 feet in diameter and 3 feet deep was dug in the hillside about 200 feet from the well and about 30 feet above it.

In this pit mud was mixed, fluid enough to flow freely, and the mixture was discharged into the blazing crater. The pit was filled and emptied three times in quick succession. The third application permanently extinguished the flames, the steam formed by the drying mud cooling the walls of the crater below the point where they would reignite the oil.

The fire burned 16 days and when finally conquered, the well was found to be flowing at the rate of about 1000 barrels daily.

The Killing of a Burning Gas Well in the Caddo, Louisiana, Oil Field[1]

The well is situated in the SE ¼ of the SW ¼ of Section7, T. 20 N., R. 15W, on a 10-acre tract owned by B. G. Dawes, Trustee. Work on the well was started on March 17, 1908. On May 11, 1908, the drillers had reached a depth of 2,065 feet. The well was cased off with 300 feet of 10-inch casing and 900 feet of 8¼-inch casing. The 6-inch casing had not been set. During the day the well began to give trouble and blew out from the 1,800-foot gas stratum. The drilling mud was made as heavy as possible and the driller started to pull the 4-inch drill pipe out of the hole to change

[1]Transactions A. I. M. E., by C. D. Keen.—Vol. XLVIII, Page 676.

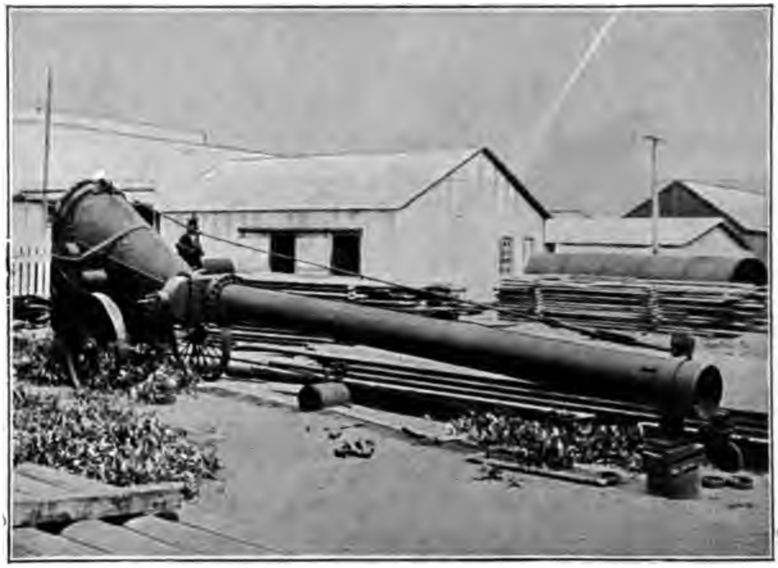


Fig. 110-A—Portable extinguisher for small gas fires.

Fig. 110-B—First stage in putting out gas fire with portable extinguisher.
—Photos Courtesy of United States Bureau of Mines.

the bit. In the night during a heavy rain storm, while the 4-inch drill pipe was being put back and was about 350 feet from the bottom, the well blew the drilling mud out again with much more violence than before. The gas pressure raised the drill pipe up, this unlatched the elevators, and the drill pipe dropped 350 feet in the hole.

The well continued to blow out, increasing all the time in volume, which was estimated the next day at 40,000,000 cubic feet in twenty-four hours. The well also made a strong salt water flow. The owners of the well did everything in their power to get the well under control. A lubricator was made of two pieces of 8¼-inch pipe and screwed on the 8¼-inch casing to kill the well, but as soon as the valves were closed the gas broke the seats of the 8¼-inch and the 10-inch casings and began to blow out under the derrick floor. The valves on the lubricator had to be opened up again to release the pressure from the casing, but the flow of gas around the 8¼-inch casing had relieved the pressure of the drilling mud on the 800 foot gas, which now started to blow out between the 10-inch and the 8¼-inch casings.

On the evening of May 13 a cyclone completely destroyed the derrick and drilling rig. A deep hole was dug around the 10-inch casing, with the well open, flowing gas and salt water, with the object of putting a cement block around it, which might hold the gas back long enough to lubricate the well. At 20 feet from the top a split was found in the 10-inch casing. After several days the drillers succeeded in getting a joint of 14-inch pipe over the 10-inch pipe and the two were cemented together, and a big block of solid cement was placed around the casing. The cement was allowed several days to harden, while the well was blowing gas and salt water. Then a second attempt was made to lubricate, but the pressure was so strong that the gas escaped outside the 10-inch casing into the shallow water sand, which is found at about 75 feet in that part of the field, and blew out on the ground about 300 feet away from the well. The well had to be opened up again and all the material brought in safely and a last attempt made to kill the blowout. But the gas continued to escape around the well, coming closer and closer to the hole. The owners then abandoned the well, considering it impossible to get it under control. In less than three weeks time the escaping gas and water had formed a

A. Second stage in putting out gas fire.

B. Third stage.

Fig. 111

— Photos Courtesy of United States Bureau of Mines.

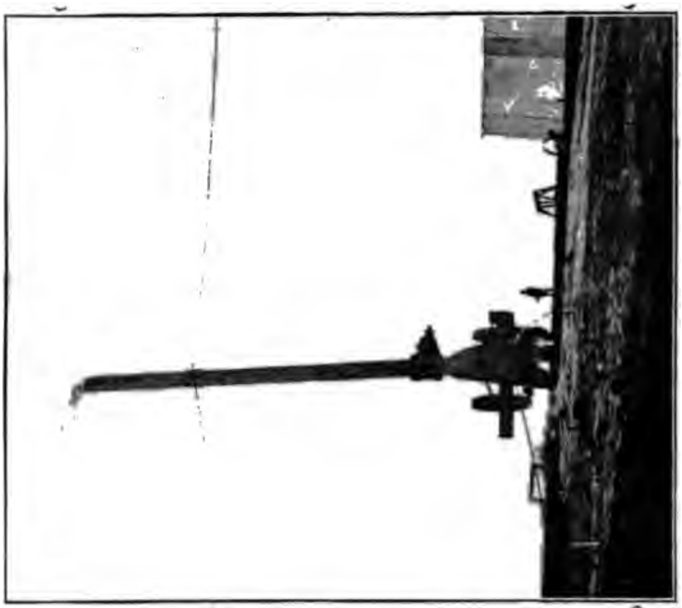
crater around the well at least 100 feet in diameter, which the waves made larger and deeper as the time passed.

In June, 1908, the well was put on fire because the gas was a continuous danger to those who had to work and live in the surrounding woods. The well stopped burning in February, 1909, but caught fire again soon afterward. The well was allowed to run wild until the summer of 1913. Most of the time the gas was burning, but heavy rainstorms and wind would put it out. After a few days the gas would catch fire again. The muddy waves caused by the escaping gas kept on washing more and more material in the hole, thus increasing the size and depth of the crater, until finally they had formed a circular pool 225 feet in diameter in the center of which the escaping gas threw up a body of mud 25 or 30 feet high.

The volume of the gas escaping from the well at the end of its life was estimated by experts to be between 8,000,000 and 10,000,000 feet per day. Not only was this waste of gas deplorable, the value of which, at about 2½ cents per thousand cubic feet at the well, amounted to about $250 per day, but also the well affected the rock pressure of the surrounding territory, which had fallen below 100 pounds to the square inch, and allowed the water which occurs in the bottom of the Nacatoch sand to enter the gas formation.

Killing of the well.—When the Conservation Commission took the matter in hand it was decided to first empty the pool which the blowout had made, to find the condition of the casings. It took about 20 days to empty the crater. The bottom of the pool sloped from the border for about 50 feet until it reached a depth of about 10 feet below the surface. From there the crater had a conical shape, with a diameter of about 125 feet sloping down to the old bore hole, where it had a depth of about 37 to 40 feet. The top of the 10 and the 8¼-inch casings could be seen at the bottom of the crater. The well was not blowing outside the 10-inch casing. Evidently after the pressure of the well had gone down, the caving mud had fallen around the 10-inch so that the water and gas could only escape between the 10-inch and the 8¼-inch casings. It was observed that the well blew out cold salt water, which indicated at what depth the blowout was taking place, because the salt water found in the deep sand rock is warm, whereas the water from the Nacatoch sand has a much lower temperature.

A. Fourth stage in putting out gas fire.



B. Fifth stage.

Fig. 112

—Photos Courtesy of United States Bureau of Mines.

The tops of both casings were worn very thin and it was impossible to screw any connections on them. The original plan was to set a disk wall packer inside the 8¼-inch casing on 4-inch pipe about 100 feet from the top and let the well blow through the 4-inch pipe, then pack the space between the 8¼-inch and the 10-inch casings with the stuffing box casing head and make a cement block outside the 10-inch casing, after which the well perhaps could be closed in. But the condition at the top of the casings would not allow this scheme to be carried out. Then it was decided to drill a well, which was called a "relief well," as close to the old hole as was possible under the circumstances, and to try to stop the flow of gas and water by pumping water or mud in the gas formation. The contract for drilling the well was let to W. W. Blocker.

When the pumps were moved the crater filled up with the salt water thrown out by the well.

This relief well was drilled on the southeastern side of the crater, at a distance of 125 feet from the center. The hole was cased off with 211 feet of 10-inch casing and 792 feet, 11 inches of 8-inch casing, both cemented. The 8-inch casing was set on the top of the Nacatoch sand. The cement was allowed to harden for 9 days, after which the seat of the 8-inch casing was tested. Mr. Smith ordered the well to be drilled with clear water 20 feet in the Nacatoch formation. The sand encountered inthis 20-foot was not porous enough, in the judgment of Mr. Smith, to attempt to pump water. The well was then drilled 20 feet deeper in the same formation, the total depth being 832 feet.

The formation found in the last 20 feet was a coarse sand rock, considerably more porous than the first 20 feet below the 8-inch casing. It was decided to make the experiment at this depth. A reservoir covering three acres of land, ranging in depth from 6 inches to three feet, was filled with water, and the 8-inch casing was connected with the pump and the full pressure put on the formation.

The pump used was the ordinary 10x6x12-inch rotary drilling pump; the boiler pressure was 120 pounds per inch and the pressure put up by the pump as registered by the gauge was 310 pounds per inch. After the hole was filled the pump ran at about five revolutions per minute for one hour, corresponding to a volume of about 29 gallons per minute being forced into the gas formation. During

the next five hours the number of revolutions increased slowly from five to 10 per minute, but the gauge registered the same pressure. During the following days the full pump pressure was left continually on the well, the number of revolutions increasing gradually and the pressure against which the pump had to work decreasing. After the fifth day the pressure registered on the gauge was about 150 lbs. to the inch and the number of revolutions 30 per minute, which was equivalent to a volume of 165 gallons being forced into the gas sand each minute.

On the seventh day the pressure was 50 lbs. to the inch and the pump was running at the rate of 42 revolutions per minute. It was noticed that the pressure would fall considerably for a short time and then run up again to where it had been previously, which can only be explained on the hypothesis that the water opened up a new channel in the formation, thus relieving the pressure, and when the cavity was filled the pressure went up again to the point where it had been before. From the seventh day on a slow decrease in the strength of the eruptions was noticeable, and on the tenth day the eruptions ceased. At the moment the eruptions stopped the salt water and the mud in the pool flowed back in the old bore hole, leaving the crater entirely empty.

Although there was no gas escaping from the hole, the pumping was continued for three more days, to drive the gas still farther back in the formation and away from the well.

The space between the 8¼-inch and the 10-inch casings was filled with cement and a heavy block of cement was put around the 10-inch casing. Then several blasts of dynamite were fired around the circumference of the crater about 10 feet apart. The explosion caused several tons of shale and clay to fall to the bottom of the crater. If the well should start to flow gas and salt water again, the salt water would mix with shale and clay and make a thick mud, which would kill the well.

Although the blowout was killed successfully, and the possibility that the well will again give trouble is very small, the derrick and casing were not removed from the "relief well" as a further precaution, so that work can be started at a moment's notice to pump water in the gas sand and cut off the flow of gas.

Value of gas wasted and conserved.—A low estimate of the average production of the well during the five years that it ran wild

Fig. 113.—Placing a hood made from a 36-inch stack over a burning gas well. First stage.
—Photo Courtesy of United States Bureau of Mines.

puts it at 15,000,000 cubic feet per day. The volume of natural gas which escaped into the atmosphere during this time would be 27,000,000,000 cubic feet. At 2½ cents per 1000 cubic feet, this volume of gas represents a value of $675,000.

In the town of Shreveport the selling rate for manufactured gas

is 7 7-10 cents per 1000 cubic feet. If all the gas which went to waste at the burning gas well had been sold in the city of Shreveport for manufacturing purposes only, it would have brought in $2,079,000.

At the time the well was killed the eruptions were still very violent and during the last year no decrease in their strength had been noticeable. No doubt it would have been several years before the burning well would have died a natural death. It is impossible to estimate the value of the gas that has been saved by the energy and the activity of the Conservation Commission, but from the above figures it can be seen that it must amount to several hundred thousand dollars.

The cost of drilling the "relief well" and putting out the burning well was approximately $6,000, which is a very small amount in comparison with the value of the gas saved.

CHAPTER IV.

THE TREATING OF OIL EMULSIONS

General Considerations

The treating of oil emulsions is a problem that must be met with sooner or later in the history of every oil field. Emulsion is commonly referred to by the men in the field as "B. S.", which seems to be an abbreviation for either "base sediment" or "bottom settlings." "B. S." is an emulsion formed by petroleum and water and a third agent consisting of a chemical composed of the alkaline salts out of the water and the petroleum acids out of the oil. Inert materials such as common sand and wet clay can also be present and it has been proven that they are very potent in certain phases of emulsion formation. It is the general belief that emulsions will not form in soft waters. Emulsion formation is effected by means of agitation, either in the well or after the oil reaches the surface and is purely mechanical. Emulsions when allowed to stand exposed to the air become oxidized and "set." Such emulsions are very difficult to handle.

Emulsions vary in character depending on the kind of oil, kind of water, degree of agitation, etc. As a general thing, it may be said that emulsions formed with light oils are easier to treat than those formed from the heavier oils. Instances have been noted, however, of oils of light gravity which made very obstinate emulsions.

The percentage of water in emulsions varies from 2 per cent to 65 per cent. Some of the water will ordinarily settle out on standing but quite commonly about 25 per cent of water is so intimately united with the oil that treatment is necessary in order to effect a separation.

Methods of treating emulsions (or dehydrating oils) are commonly divided into six classes, as follows:

1. Treating by heat in open tanks.
2. Treating with heat in closed receptacles:
   Dehydrators
   Topping Plants.
3. Treating by electricity.
4. Treating with chemicals.
5. Treating with centrifuges.
6. Various combinations of above.

Treating by Heat in Open Tanks or Pits

It has been known for years that almost any emulsion could be treated by raising the temperature to the boiling point of water. This is ordinarily done by heating the emulsion with steam pipes and this is quite commonly carried on in open tanks or pits, especially in the Gulf Coast region. Ragsdale in The Oil Weekly (1920 Statistical Edition) has the following to say about this system:

> In former years this method was practiced almost exclusively, chiefly because it is the most simple—the first one thought of.
>
> One company on the Gulf Coast uses 600-barrel tanks for boiling the oil. The emulsion is run into the tank where it is heated by means of steam coils. The temperature to which the emulsion must be heated depends to some extent upon the character of the emulsion and varies from 160 degrees to 300 degrees F.
>
> The cost of fuel is not the only cost to be computed. The loss by evaporation must be considered. Whenever heavy oil is heated to a temperature as high as is required to get rid of the water content some oil is volatilized and lost.
>
> The lighter vapors contained in the oil, these possibly of the highest value, are driven off by the heating process and are completely wasted and lost. There is no way of computing the cost because of this waste, as there is no way of telling what vapors are driven off and in what quantity.
>
> The Humble Oil & Refining Company estimated its cost of boiling or heating for dehydration at 8 cents per barrel. This was several years ago when oil was worth only one-third of what it is now. It is safe to estimate that the present day (1920) cost would run nearer 20 cents per barrel. Several companies which have employed this method have estimated their cost between 15 and 20 cents per barrel.
>
> But all that is said of the heating or boiling method must not be derisive. The method is being used at this time in certain coastal fields where other means of dehydration have been found more or less unsatisfactory.

Mr. C. H. Homer furnishes the following interesting description of certain methods of treating emulsions in pits:

> The oil is led from one pit to the next and in cases partitions are placed in each pit so that the travel of the oil is increased. These pits are provided with coils and a body of water is kept below the oil, the latter flowing over the water in a layer 4 to 8 inches in thickness. The entire contents of the first pits are kept in ebullition while that in the last pit of the series is quiet. The earth acts as a partial insulator for this type of treater but there is a corresponding loss in seepage, the hot oil penetrating the surrounding soil for much greater distances than will cold oil. There is also the loss from vapors as referred to above.
>
> Another refinement of this type of open pits is a concrete trough 60 feet in length and 4 feet in depth, used by the Sun Company at Saratoga, Texas. A series of coils covers the bottom of this trough between concrete partitions of two feet in width. The oil enters at one corner, runs the length of the trough, through an opening, and back; this is repeated and the finished oil taken from the corner opposite the entrance. This form disposes of seepage so long as the concrete remains intact. The vapor loss remains.

A process in use in California is described by Paine and Stroud ("Oil Production Methods"). This consists of a spray pipe in the bottom of a tank. The tank is filled to about 10 feet with water kept heated to 200° F. by suitable steam coils. The oil is sprayed up through water by the finely perforated pipe allowing the emulsion to separate into constituent parts. The oil accumulating at the surface being led away.

W. G. Williams, consulting engineer of Oklahoma City, announces he has developed a system of dehydration for the removal of water from crude oil which he states is a decided improvement over the present general method of steaming the oil. Mr. Williams claims for this system that it is both less expensive and less wasteful than other methods now in use, with a reduction of 50 per cent in operating costs.

Mr. Williams is giving his process to the oil industry, in the belief that it will prove of practical benefit, and will be a forward step toward better efficiency.

The apparatus consists of a series of units of three pipes telescoped together. The cold emulsion enters the middle pipe of the first unit, and passes through each unit until it reaches the last, where the final temperature is attained, steam being used in the last two units in the outside and inside pipes.

From the middle pipe of the last unit the emulsion, having reached the temperature required for breaking apart the oil and water, reverses its course and passes back through the inside and outside pipes of those members wherein steam is not used, giving up its heat to the incoming cold emulsion, and leaving the system at a point adjacent to the original point of entrance, at a temperature slightly above that of the cold emulsion.

The maximum temperature required governs the pressure of the steam used for heating, and the safety valve on the boiler may be set so that the required final temperature of the emulsion shall not be exceeded.

As the steam is condensed it is automatically returned to the boiler by a return trap, so that the only heat loss is reduced to that of radiation. The steam requirements are 12 boiler horse power per thousand barrels per twenty-four hours, with a final temperature for the emulsion of 150° F.

Treating by Heat in Closed Receptacles

The next step in the development of the heat treatment of emulsions was the perfection of the "dehydrators" or closed receptacles of various types in which the emulsion was heated. The vapors evolving from these dehydrators are collected and condensed and a considerable amount of distillate recovered. The dehydrators vary considerably in design and range from the elaborate Trumbull system, which is really a sort of refining system or "topping plant," to simple sheet iron boxes containing coils and having a dome in which the vapors are collected. Some of the dehydrators are operated with direct heat, while in others steam heat is used. The hot, cleaned oil coming from the dehydrators is usually employed in heating the in-going cold emulsion.

Dehydrators.—Mr. C. H. Homer has perfected one of the "trough" type of dehydrators at Saratoga, Texas, for treating emulsion containing 19° Be. Coastal crude oil. He describes it as follows:

> The trough is 40 feet long by 5 feet wide and 14 inches high, for 30 feet of its length, widening from this point to a height of 24 inches at the outlet. The baffles are placed at intervals of ten feet and extend the width of the trough and to a height of 6 inches above the bottom. The steam coils are 9 feet in length and 4 feet in width, each coil being connected to the main header through a valve, thus permitting of the use of as many

of the coils as is required to reduce the emulsion. The coils are made of 1¼-inch pipe using return bends. However, a manifold with packed joints, permitting greater flexibility, has been designed and will be substituted in future installations. The exhaust from all the coils is run the full length of the trough, being packed where it passes through the baffles, in such manner as to allow for expansion. A steam trap is provided at the end of this exhaust , the hot water from which is passed over the cold incoming emulsion. Additional heat exchange is effected by passing the cold incoming oil through coils placed in the tanks receiving the hot oil at the outlet of the trough.

A tight fitting cover is bolted to the top rim of the trough. The lighter hydrocarbons and water vapors are led from the trough by means of 4-inch pipes leading to an 8-inch header which in turn is connected to a condenser. The condensate or crude distillate is later split into salable products, gasoline, engine distillate, etc., in a standard still.

The finished oil is caught upon an apron below the outlet and flows into a 75 barrel galvanized iron tank which has an outlet opposite the apron and at the top into a second 75 barrel tank. Water is held in this tank to within 8 inches to 12 inches of the outlet. The water level being shown by a sight glass.

The length and width of the treater are governed by the amount of oil to be treated, the height by the tendency of the oil to froth. Sufficient height must be given to prevent the froth being carried up the escape pipe with the lighter oils.

In perfecting the trough a great many tests were made with and without baffles and with baffles of varying heights. It was found that with an oil of 20 per cent impurities a product showing less than ½ of one per per cent could be made at the rate of 1500 barrels per twenty-four hours, using baffles 4 inches to 6 inches in height.

The oil outlet pipes are turned down inside the trough to a depth which will keep the inside ends submerged at all times. This prevents the escape of gasses from the trough regardlss of the pressure. In addition to the water sight glass at the outlet end of the trough an 18-inch glass is provided for the purpose of holding the fluid height above the outlet pipes, otherwise should the trough have a pressure, and the flow be checked at the inlet, the fluid level would drop until it was below the turned down ends of the outlet pipes and an escape of gas would result. This would necessitate a readjustment of the flow and cause some delay.

Topping plants.—In California some very elaborate dehydrating or topping plants have been erected. A typical installation is described by A. F. L. Bell in the Transactions of the American Institute of Mining Engineers, as follows:

A new plant was erected under the design of E. I. Dyer. chief engineer for the Union Oil Company. This plant, of which A. Roy Heise is superintendent, is at Avila, near Port Harford, about 40 miles from the Santa

Maria field, the oil being delivered to the plant from the field by two pipe lines; one 6 inches and the other 8 inches in diameter. This plant, although designed several years ago, is still one of the best topping plants on the Coast. It is topping oils in some cases carrying as high as 20 per cent water at the same cost for fuel and labor as some other plants topping oils carrying only 2 or 3 per cent water.

The heat used in topping comes from steam at 150 lbs. pressure generated by a battery of five 300 h. p. Stirling boilers in a separate boiler house. There are 12 cylindrical steam stills mounted in a steel-frame structure in a separate building, the stills being mounted in a double row of

Fig. 115.—Photographs of oil emulsions as seen under the microscope. (By Courtesy of The Petroleum World.)

six each, one row above the other. Those in the upper set are known as the low-pressure stills, those in the lower as th high-prssure stills. Live steam is admitted to the lower row only, the steam passing into the body of the still by a number of 1-inch return pipes.

Each steam still is about 6 feet in diameter and 20 feet long and has a steam chest mounted on its front end having three separate compartments. The live steam is admitted to one compartment and passes to the next com-

partment through a series of 1-inch continuous pipes. These run from the initial side of the steam chest the full length of the still, and return to the next compartment of the steam chest, and in the same manner to the third compartment, so that there is no connection of live steam between any of the compartments of the steam chest except through the heating-coils. The condensed water is trapped out of each compartment so that a minimum quantity of condensed water travels through the coils.

As the steam is condensed, it drains to traps and is returned to the boilers at 280° F. No live steam is admitted to the upper tier of stills, the heating agent being the vapor from the bottom still, which rises and enters the steam-chest of the upper still and passes through the still in the same manner as the live steam entered the lower still. The vapor pressure in both the lower still and inside the coils of the upper still ranges from 40 to 50 lbs. The pressure is maintained at a point where the radiation of the latent heat through the coils to the liquid in the upper still is equalized by the heat from the vapor rising from the lower still. As about half of the vapor is steam, the temperature corresponds closely to that of saturated steam of the same pressure. No vapor leaves the coils of the upper still. Only the condensed liquids are trapped off. These go to the same condenser as the vapors from the low-pressure still. By this means all the latent heat in both the oil and water vapors is absorbed by the oil and water in the upper still, thereby effecting a saving of about 50 per cent of the fuel necessary to top the oil in ordinary stills. The vapors from each low-pressure still flow into the condenser belonging to that battery, which is mounted on the top of a steel framework outside of the steam-still house.

There are six separate condensers, each connecting to a battery consisting of a high and low-pressure still. The condensers are rectangular. They have a vapor-chest at the rear end of the same general design as that of the steam-stills, except that the dividing partition in the chest is horizontal. The vapors are admitted to the upper portion of the chest and pass through a series of 2-inch return pipes, surrounded by the condensing water, returning to the lower portion of the chest. From this point they drain to the proper storage tanks.

Mounted below each condenser are two heat exchangers set one above the other. These heat exchangers are similar in construction to the condenser except that they have 1-inch return pipes, and have two vertical dividing partitions in each chest. In addition, heated residuum surrounds the pipes instead of water. The heated residuum from the high-pressure still passes into one end of the body of the upper exchanger and travels backward and forward four times, guided by interior partitions. It then passes into the end of the body of the lower exchanger, again traveling backward and forward four times before passing out as finished residuum to storage. In all condensers and exchangers, the liquids counterflow.

The crude oil in taking up the heat in the exchangers comes into one side of the chest of the lower exchanger, passes backward and forward twice through a series of 1-inch return pipes and then is discharged from

the opposite side of the chest to the upper exchanger. It passes through two series of return-bend pipes in the upper exchanger, leaving the chest on the opposite side from where it entered. It flows to the low-pressure still ,and after giving off a portion of its vapors of oil and water, is pumped to the high-pressure still where practically all of the remaining distillates are taken off. The treated oil from six high-pressure stills passes to the exchanger.

This is an economical system. Practically the only steam admitted to the plant is through the high-pressure stills, so all of the work done in the low-pressure stills is an absolute saving. The plant is running on what is known as double effect. At times it has been run on triple effect, that is, live steam was introduced into the first still only and the heated vapor from the first still under pressure was admitted to the coils of the second still, and the heated vapor from the second still, necessarily under a lower pressure, was admitted to the coils of the third still, the crude oil flowing

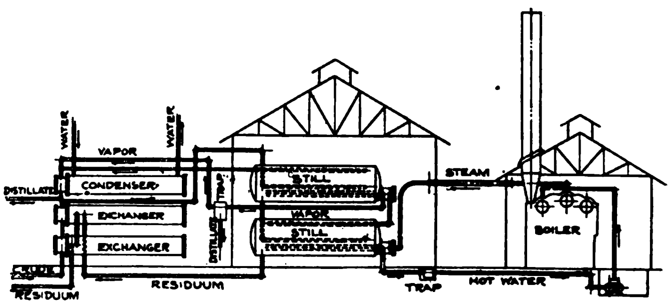


Fig. 116.—Union Oil Company plant at Avila.

first to the low-pressure, then to the intermediate ,and finally to the high-pressure still. As might be expected, this method showed a greater saving than with double effect, but reduced the quantity of crude oil that could be treated in a given time.

Distillation by Double Effect

	Water Pct.	Distillate Pct.
Evaporation from low-pressure still................	56.95	34.45
Evaporation from high-pressure still................	42.05	64.15
Evaporation interchanger and unaccounted..........	1.00	1.40
	100.00	100.00

Distillation by Triple Effect

	Water Pct.	Distillate Pct.
Evaporation from low-pressure still................	55.80	37.42
Evaporation from intermediate still................	29.75	31.36
Evaporation from high-pressure still................	13.42	29.74
Evaporation from interchanger and unaccounted....	1.03	1.48
	100.00	100.00

From the above figures, it will be seen that with the double-effect ar-

rangement about 50 per cent of the fuel is saved, and with triple effect about 75 per cent, over a single system of evaporation.

For a given period, the average temperature of the crude oil entering the heat exchangers was 61.67°F.; leaving the heat exchangers before entering the low-pressure stills, the temperature was 141.45° F., showing a saving by rise in temperature due to exchangers of 79.78° F.

The economy o fthe plant is shown by the following table:

Duty Records Per Barrel of Dry Fuel Oil Used for the Last Three Months of 1919

Barrels of crude oil treated	63.35
Barrels of water actually removed from crude	10.67
Barrels of residuum produced	42.34
Barrels of distillate produced	8.54
Barrels of residuum pumped from plant	43.80
Barrels of distillate pumped from plant	9.52
Barrels of circulating water pumped	156.46
Barrels of miscellaneous oil pumped	9.08
Kilowatt hours—lighting, power, etc.	2.53

Thermal Duty of One Barrel of Dry Fuel Oil	B. t. u.
Evaporating water from crude oil	4,135,984
Evaporating distillate from crude oil	425,128
Kilowatt hours—lighting and power	35,940
Total useful duty	4,597,052

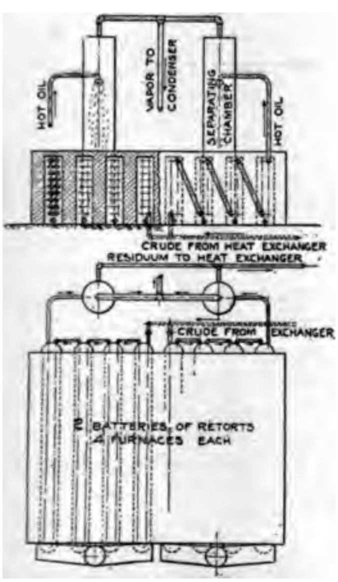


Fig. 116a.—Topping plant, Union Oil Company refinery at Brea.

This system is ideal for Santa Maria oils and entirely eliminates the coking which takes place when direct heating is used under ordinary stills or retorts. The water carried by the oil is as salty as sea water and when evaporated throwns down salt crystals in the stills. In the case of fire-heated stills, this salt mingles with the coke and forms a hard incrustation, which necessitates closing down frequently and chipping out the coke; whereas with this form of still, when salt crystals are formed, the operators employ the unique method of shutting down the stills about once a week, emptying the stills of oil and filling with water and then heating the water, thus dissolving the salt and passing it off by pumping a continuous stream of heated water through the stills. Two patents on this system have been applied for by Mr. Dyer and are now pending in the patent office.

The Union Oil Company has two other topping plants situated in the Fullerton field. The most important is the Brea refinery, A. Edmund Hildick, superintendent. This plant shows clearly the development of the art of topping, having been constructed in August, 1911, to handle the light oil from the Birch well, which produced about 2400 barrels per day of "gassy" oil when first completed. The plant when first started treated successfully about 100,000 barrels per month of clean dry oil carrying not more than 0.5 per cent water and removed 22 per cent of 53° Baume tops. The old part of the plant consists of eight old 40 h. p. drilling boilers, which have half the tubes removed. These boilers are set in two rows of four, facing each other with an alley between them. The oil is run through each battery of four boilers continuously. It has since been demonstrated that this plant is not adapted to handling wet oils and will not work successfully with oils carrying more than 2 per cent water.

The next step in increasing the capacity of the plant was the building of an additional topping plant in March, 1913. This consisted of two batteries of retorts, each battery being divided into two separate divisions, each division having four furnaces and each furnace carrying a double row, six pipes high, of 3-inch return pipes, 20 feet long. Each division of the battery is fed with crude oil independently. The oil admitted to the bottom pipe of the furnace travels up through the 9 coils, coming out the top and returning to the bottom pipe of the next furnace, again leaving the upper pipe and so on through the four furnaces. The heated oil from each side of the battery flows by independent pipes to one of the separators. This makes each 8-furnace battery with one separator a single unit.

The vapors are then led from the separating chambers to the condensers and on to the storage tanks. The residuum is taken from the bottom of the separators, passed through the heat exchangers and on to the residuum storage.

The coils in the furnace are heated by gas-fed perforated pipes running the full length of the furnace. It was found that this form of furnace is not well adapted to oil firing. A change was, therefore, made in one of the batteries, the coils being mounted horizontally in a brick furnace, allowing plenty of combustion room below. This furnace is working satisfactorily and it is likely the other half of the battery will have the coils changed from vertical to horizontal position so as to be adapted to oil firing.

The total capacity of the two batteries of retorts with gas fires was 60,000 barrels per month of 21 to 22° Baume oil, carrying 6 per cent moisture and basic sediment. From this there was topped about 10 per cent of 51° Baume distillate, giving a residuum of 18° Baume, having a flash-point between 160 and 180° F. With the change in construction and the use of oil firing, it is believed the capacity will be doubled.

The oil just before entering the separator is choked down to a pressure of 40 lbs., but flows into the separator at practically atmospheric pressure. This choking of the oil gives a backward pressure at the inlet end of the retorts at the furnace of 80 lbs. The crude oil leaves the heat exchanger and

enters the first coil of the retort at 180° F.; it leaves the coils and enters the separators at about 450° F. This refinery not only tops oil but turns out finished gasoline, but as the purpose of this paper is to describe topping plants only, no description will be given of the other details of the plant.

Treating Oil Emulsions With Electricity

The following description of electrical methods is given by Ragsdale in the Oil Weekly:

The electrical process of dehydaration of emulsified oils involves the passage of the oil, as it comes from the wells, between two electrodes separated at a distance, which is governed by the water contents in the oil. The electrodes are connected to a source of electricity of sufficiently high potential to create an electrostatic field, or field of electric strain, whcih will cause the minute globules of water to conglomerate and coalesce until they become so large and heavy that they will settle out from the oil by gravity. The electricity in passing through the oil does not heat it to any appreciable degree.

There are two types of electric dehydrators in general use, the National and the Cottrell. The basic patents covering both of these methods of electric dehydration of crude oil emulsions are owned by The Petroleum Rectifying Company, the use of which is allowed oil producers by executing a license agreement with the company.

The National type (Fig. 117) is described as follows: The treater consists of a sealed tank, 8 feet in diameter by 15 feet high and vertical plates termed 'polarizers' serving as electrodes, each alternate plate being grounded to the tank. The oil to be treated enters the lower portion of the tank through the inlet pipe and passes up through the electrodes, the cleaned oil being drawn off the top to the shipping tanks, and the water settling to the bottom and passing out through the goose neck near the water bleeder. The tank is at all times during its operation kept full of oil.

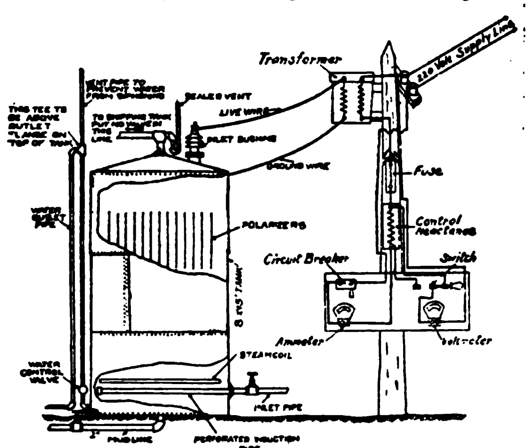


Fig. 117.—Diagramtic sketch of National type electric dehydrator.

In the Cottrell type (Fig. 118) each unit consists of a galvanized metal tank, approximately 3 feet in diameter at the base and 10 feet, 7 inches in overall height, the shell of the tank forming one electrode and circular discs

mounted on a vertical shaft, slowly revolved through suitable gearing forming the other electrode. The oil emulsion is fed into each unit or treater at the top and passes down through each treater where it is drawn off the bottom and led to a trap or separating tank where the water is allowed to settle and bleed off the bottom, the dry oil being drawn off the top of the separating tank through an adjustable swing pipe.

Although the Cottrell plant has revolving electrodes and is somewhat different from the National in mechanical construction, yet in theory the

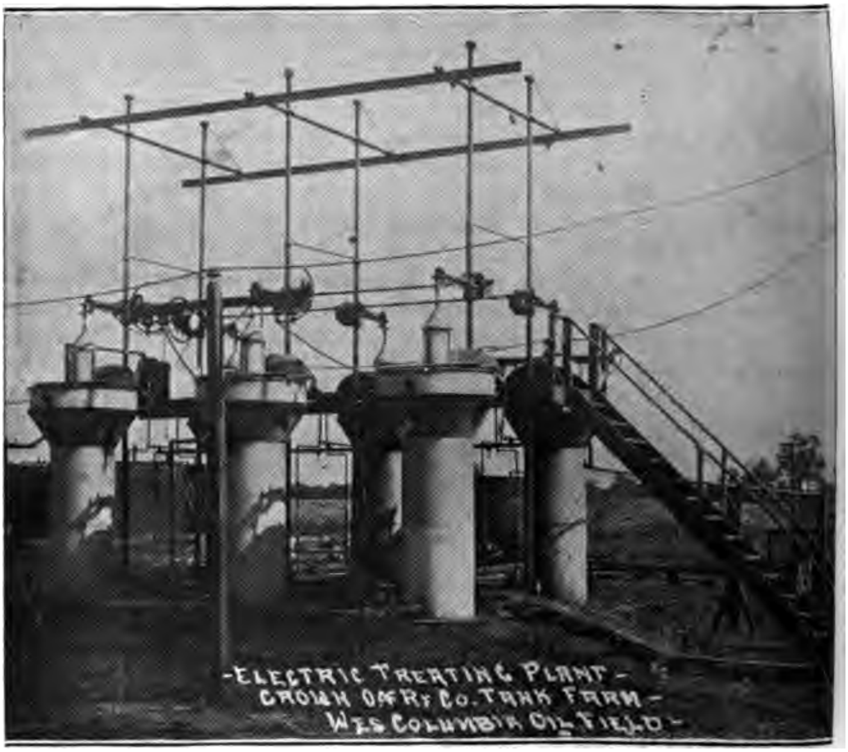


Fig. 118.—Six unit Cottrell type electric treating plant, Crown Oil & Refining Company. West Columbia field.

two types are alike. It has been found, however, that in treating certain kinds of emulsion, the revolving electrode is essential in preventing continuous short circuits.

In 1911 the first electric dehydrator was put into operation in the California fields. At that time the only method known and used by the operators was the treatment by the steam heating process. This system was unsatisfactory in more ways than one, but the principal objection was the high cost of producing the required amount of steam and the evaporation

loss in light vapors. In many cases in using the steam process it was found necessary to use a temperature as high as 400 degrees Fahrenheit in order to break down the emulsions found in low gravity oils of 14 degrees Baume or less which are produced in large quantities in California. Owing to the greater economies shown by the electric process, it has steadily replaced the old steam treating system in California to such an extent that today it is recognized by the large producers of that state as the most economic and practical method available.

The electric dehydration process was successfully introduced into the Gulf Coastal fields of Texas about one and a half years ago, and plants

Fig. 119.—The National dehydrator.

are now in operation or in course of construction in the Goose Creek, West Columbia, Hull, Humble and Saratoga fields. A great saving has been made by the oil companies in these fields by the adoption of this process and in many cases, two boilers formerly required to treat a certain amount of oil have been eliminated by the installation of one electrical unit. This saving has been particularly pronounced recently due to the high market value of fuel oil.

In substituting the electrical process for the steam heating, a saving

of six to ten cents per barrel of cleaned oil has been shown in the actual cost of dehydration.

The electric power consumption per treater is remarkably low, varying from 6 to 15 kilowatt hours per twenty-four hours. This consumption represents an average cost of about 40 cents per day, based on the prevailing rate in the Gulf Coast fields of four cents per kilowatt hour .

The treater capacity in net oil dehydrated depends considerably upon the character of the emulsion to be treated, but a fair average of 1500 barrels per twenty-four hours can be placed in the National plant and 2500 barrels per twenty-four hours on a six-unit Cottrell.

It has been found that the percentage of water and emulsion in the oil is not the determining factor in the capacity of the treater as in numerous cases oil containing as high as 85 per cent water and emulsion is being reduced with compaartive ease to a water content of less than half of one per cent.

One of the main features of the electric system is its simplicity of operation. It is practically fool-proof, does not require an expert attendant and is continuous in its operation.

Electric process, direct current[1].—The process consists in passing the emulsion between electrodes connected to a source of direct current electricity with a potential of from 250 to 400 volts, with a current varying from a few milli-amperes to 10 amperes. The patent under which the direct current electrical treatment is operated claims that the process depends upon cataphoresis or electrical migration. The original experiments which served as a starting point for the development of this patented process were performed by the author with the help of Mr. G. W. Jones in May, 1917, and the idea was based upon the known migration of colloidal particles when subjected to electrical stress. This migration of particles must be a factor. Some electrolysis doubtless takes place since the electrodes are only about ⅛-inches apart and at times a considerable current passes.

Treating Emulsions with Chemicals

Within the past few years the treating of emulsions with chemimcals has come very much to the front in the United States. Sherrick in the Transactions of the American Chemical Society describes the theory of the process as follows:

There are on the market certain compounds for the treatment of oil field emulsions. These compounds are usually crude soaps or sodium salts of sulfonic acids, obtained by sulfonating either a coal-tar oil or a petroleum. All of such compounds examined were hydrophile colloids, which seems to be the explanation for their action in discharging these oil field emulsions.

Just as there is selective adsorption of ions, so there is selective ad-

[1]Described by Sherrick in Trans. Am. Chem. Soc.

sorption of colloids, and certain hydrophile colloids might have a much greater tendency than others to destroy an emulsion formed by means of a given hydrophobe colloid. Just as precipitation of collodial particles is due to the adsorption of an ion with a charge opposite to that upon the particles, so colloids of opposite character precipitate one another. But in the destruction of an emulsion formed by a hydrophobe colloid it is not necessary that the hydrophile colloid be of an opposite charge. Thus we have negatively charged soap particles precipitating the negatively charged water particles of these emulsions.

Ragsdale in The Oil Weekly (1920 Statistical Edition) has the following to say relative to the Tret-O-Lite process for treating emulsions:

Removing b. s. by a chemical, without the use of equipment other than that already used on every oil lease is the idea conceived by William S. Barnickel, a chemist of St. Louis. Mr. Barnickel has put his idea into operation in various fields and with notable success, especially in West Columbia, Texas.

No extra equipment is needed by a producer who adopts Mr. Barnickel's process. The chemical which is shipped in 50-gallon drums, is mixed with the oil either at the pump or in the pipe line.

Different oil emulsions require a different chemical mixture, the change being made at the laboratory after a sample of the emulsion has been sent. It took Mr. Barnickel years to ascertain what chemical change was neccessary in order to meet the dehydrating requirements of the different emulsions. The Tret-O-Lite process has been especially successful in removing emulsions from West Columbia oil, both The Texas Company and the Humble Oil & Refining Company using it extensively.

The cost of dehydrating by this method is exceedingly low in that particular section. Frank Sterling, vice president of the Humble Oil & Refining Company, estimates that the cost does not exceed one and one-half cents a barrel. More than 15,000 barrels of oil a day has been dehydrated at West Columbia by means of the Tret-O-Lite process. It has been found that "old" or "tank" oil yields as readily to the corrective properties of the chemical as that oil which is fresh out of the well.

Very little of the chemical is required in the treatment of the emulsions; so the freight cost of the full drums from St. Louis is not prohibitive. A barrel of the chemical is sufficient to treat between 10,000 and 15,000 barrels of the West Columbian emulsion. As stated heretofore no extra equipment is required, the chemical being fed into the pump which picks up the oil to be treated.

Treating Emulsions with Centrifuge

The method of treatment with centrifuge has been described by R. M. Gotham of the Sharples Specialty in The Oil Weekly:

Briefly, the integral part of this process is the super-centrifuge in which

the emulsion is separated into its component parts of oil and water and these two liquids are discharged separately from each other.

Another essential part, however, of the installation is the proper arrangement of the accessory heating tanks and coils so that the emulsions may be put in the proper condition before centrifugal treatment.

The various pipe line companies who have accumulated large quantities of tank bottom emulsions at their tank farms are now cleaning up these accumulations through the installation of two to five centrifugal units in connection with a portable plant. This plant can be erected very quickly and moved to a new point where it can be set up in a few days' time to treat another accumulation of tank bottoms.

There are now nearly two hundred of these centrifugal units in actual operation in the Mid-Continent fields. The Prairie Oil & Gas Company has several million barrels of tank bottom accumulations on their various tank farms which they are working over into marketable oil with wonderful success. They own fifty machines and have plants ranging in size from five to 20 units.

The most noteworthy achievement in this line is the latest plant put into operation at Cushing, Oklahoma. There a 20 unit plant is turning out an average of 2000 barrels of reclaimed oil daily. The recovery of good oil from the original stock approximates on the average 70 per cent. The residue discharged from the machines consists of 95 per cent water.

Many other companies own large plants, among which are the Empire Pipe Line Company and the Empire Gas & Fuel Company, the Gulf Pipe Line Company, the Standard Oil Company, the Gilliland Oil Company, the Magnolia Petroleum Company, Cosden & Company, and the Sinclair Company.

A large number of small independent producers have found it to their advantage to work over accumulations of various sizes, as in this day of high prices for oil it is good business policy to reclaim everything possible. It has been found that one or two unit plants will often pay for themselves within as short a time as a single month.

Combinations of Various Systems

Quite a few instances have been noted where companies use a combination of several systems of treating emulsions and they get very satisfactory results in this manner. At Goose Creek, Texas, for instance, the Gulf Production Company uses a combination of heat, direct current electrical, and centrifugal treatment. All emulsion from the field is pumped into two large earthen storage tanks at the treating plant where some natural water settling takes place. The emulsion is then picked up and heated in a closed system to 175 degrees and sent to 12 direct current electrical treaters where the emulsion is reduced from 30 per cent to about

6 per cent. The discharge from these treaters goes to a concrete pit where the top is skimmed to the pipe line oil pit and bottom pumped to 18 centrifuge machines. The oil from the centrifuges comes out at about 1.3 per cent B. S. and goes to pipe line pit. All waste from treaters and centrifuges is handled through concrete pits and nothing but clear water is let off. Every possible way of heating by exchangers in pits is taken advantage of.

In the Caddo, Louisiana, field there is a treating plant employing the following combination of methods:

Oil containing water goes first to a two compartment concrete pit where top is skimmed over into pipe line oil pit and bottom oil goes to 16 centrifuge machines. These machines separate the emulsion from the oil. The heavy emulsion thrown off by this process, after passing through a concrete settling pit where some water is bled off, goes through a closed heater to two direct current electrical treaters. Here the emulsion is broken down and clear water is bled off. The oil discharge, at a temperature of 175 degrees, is put into the bottom of the cold oil concrete pit thus eliminating any appreciable loss in heat. The volumes of the cold oil to heated oil are such that the temperature does not exceed 85 degrees.

Filtration System

Of recent months there has been developed in the Mid-Continent a method of treating emulsion by filtration through a filter made up of common excelsior. Very good results are claimed for this filter by the inventors, Messrs. Winters and McCowan. As shown in Fig. 119-A this is a very simple and inexpensive process. The emulsion is heated to about 90° F.before being introduced into the filter. Mr. H. R. Shidel in describing this process to the author mentioned one installation in Kansas which had been in operation some 380 days treating a very refractory emulsion containing about 15 per cent b. s. This filter had treated 1000 barrels of oil per day at a cost of about 1-14 cent per barrel. The oil coming from the top of the filter tested less than 1 per cent b. s.

Heat Exchangers

In treating emulsions by steam heat it is quite customary to heat the incoming cold emulsion with the outgoing hot treated oil.

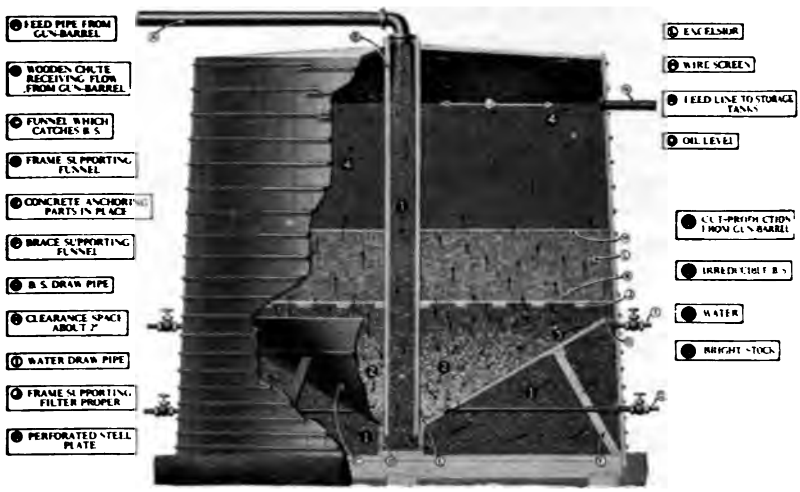


Fig. 119-a—Tank Equipped for Treating Emulsions by Filtration

Devices for doing this are known as heat exchangers. They are made up in various forms.

In calculating the amount of hot oil needed to heat the cold emulsion the following formula is commonly used:

$$H\,S\,T = c\,s\,t$$

Where:

H = weight of hot oil
S = specific heat of emulsion
T = difference in temp. of hot oil and emulsion at beginning
c = weight of emulsion
s = specific heat of hot oil
t = difference in temperature of hot oil and emulsion at end

Hence weight of hot oil needed to heat emulsion ("c" lbs.) through T degrees Fahr. is:

$$H = \frac{c\,s\,t}{S\,T}$$

It is assumed that the amount of heat lost by the hot oil equals the amount of heat gained by the emulsion. This is not strictly true as there will be a certain amount of heat lost by radiation. This latter loss can be neglected in these calculations.

CHAPTER V.

USE OF ELECTRICITY

OPERATION OF WELLS BY ELECTRIC POWER

By W. G. TAYLOR[1]

Fuel saving.—The oil fuel consumption for steam-engine pumping is from 3 to 15 barrels per well per day, depending upon the depth of well, the pumping speed, and other local conditions. For instance, in Texas the average is about 10 to 12 barrels. When such wells are electrified, all of this oil fuel can be added to net production, and this, it will be appreciated, is no small gain. Even if oil fuel is used to produce electric power, a modern turbo-generating station will require only half a barrel or less per well per day.

When gas engines are replaced by motors, of course no oil fuel is saved, but more gas is available for the market, and there is much less production lost from shut-downs.

Decrease of shut-downs.—It is only recently that oil men have begun to realize the amount of time lost, and consequently of production, due to avoidable shut-downs in pumping operations. Engine and boiler trouble, reversing clutch troubles, gas shortage, water shortage, freezing in cold weather, rod breakage, and valve and cup troubles caused by vibration and jerking motion are all greatly reduced and some are entirely eliminated by the use of electric drive. An excellent example of this fact is furnished by the records, given in Table 1, of shut-downs for all causes during normal operation of two groups of wells in adjoining Kansas oil fields. The reduction in lost pumping time obtained by the use of

[1]Published by permission of General Electric Review.

motor drive in this case indicates a resulting increase in production of about 15 per cent.

The most convincing figures are those which an oil producer can obtain from his own property. The time reported daily for shut-down should be classified under:

(1) Engine, clutch and boiler troubles.

(2) Gas or water shortage, or freezing in cold weather.

(3) Rod breakage, including time required to pull and replace rods or tubing on this account.

(4) Cup and valve troubles, including time required to pull and replace rods or tubing on this account.

(5) All other causes.

TABLE I

Comparison of Pumping Time Lost From Shut-Downs With Gas Engine and Electric Drive Under Similar Normal Operating Conditions in Kansas, Pumping On the Beam

	Gas-Engine Drive Augusta Field		Electric Drive El Dorado Field	
	Nov., 1917	Feb., 1918	Oct., 1918	Nov., 1918
Number of wells	208	216	25	27
Per cent of available pumping time lost, all causes	23.3	28.2	10.7	9.8
Per cent of available pumping, time lost, engine or electric troubles only	4.8	8.15	1.98	0.63

Care must be taken that the time recorded for shut-downs represents the actual amount of available pumping time lost, particularly on head-wells, which are pumped less than 24 hours a day, and which are often reported as being shut down 24 hours when the pumping time really lost is perhaps a much shorter time. On a 24-hour well every hour it is shut down represents a loss.

After the shut-downs are thus classified for a period of a month or two, or long enough to establish a record of average conditions, an analysis with reference to electric drive should be made on the following basis:

(1) Electric troubles will not cause over 2 per cent loss in time due to shut-downs.

(3) There will be no gas, water or freezing troubles with electric drive.

(3) The time lost from rod breakage will in most cases be cut in half if motors are installed.

(4) Although definite figures are at present not available, it may be assumed that valve and cup troubles will be reduced several per cent with motor drive.

(5) The other causes of shut-downs will probably not be materially affected as a whole, though some troubles will occasionally occur which would be directly or indirectly remedied to a considerable extent by electric operation.

That rod breakage is to a considerable extent due to engine drive has not always been appreciated. The oil well motor during pumping does not pick up the rods with a jerk as is the case with steam and gas engines, the speed of the bandwheel being practically constant for the entire revolution. The rods are therefore less liable to crystallize with resulting breakage causing shut-downs. This condition with engines may be somewhat improved by use of a counterbalance on the walking-beam, though it does not make full compensation because of the greater change in speed with engine drive as the result of even a small change in load.

With reference to rod breakage, the field superintendent of a large company in California which operates about 250 wells, of which 100 were then electrified, stated that after motors were installed this trouble was not 60 per cent of the amount experienced with steam engines. Another company using gas engines in the El Dorado field in Kansas, found that the very large amount of rod trouble which had been experienced on about 30 wells almost wholly disappeared after electrification.

Time saving.—In addition to a reduction of the number of shut-downs, electric drive shortens or eliminates many delays, such as those caused by steam lines full of water after an idle half hour, or by the usual necessity of getting up steam after longer periods of idleness, or by the engine sticking on center and obliging the operator to make a trip back to "kick it off," or by the difficulties frequently encountered in starting gas engines.

In "pulling" a well, a motor will pull the first "stand" of tubing as fast as the last one, practically regardless of the load to be lifted, while with engines the speed is considerably reduced on the heavier work.

The well-cleaning gang soon finds that quicker work can be done with motors in "spotting" rods and tubing when screwing them up, and that practically no delay is caused by over-travel when hoisting or lowering rods and tubing. This is all due to the fact that more accurate control is obtained than with any form of engine drive. As a result, the well is often put back in production sooner than with other forms of drive.

Production is frequently lost at the flush period during the time taken to set a pumping engine after drilling has been completed. No necessity for this delay exists with electric drive, for all of the pumping equipment can be installed before the drilling engine is removed, or the well can be pumped by a small motor temporarily lined up on the derrick floor while the permanent equipment is being placed and wired. Ordinarily less than an hour is necessary for the change when the proper arrangements are made.

Uniform pumping speed.—By a drop in steam pressure and quality, or in gas pressure, many a barrel of oil has been lost to the producer who uses engines for pumping. It is well known that a change of one or two strokes per minute from the proper pumping speed frequently results in a very large variation in the daily production. That motors are far superior in this respect in maintaining production is best illustrated by three cases which will be cited.

Several wells have been equipped with two-speed oil well motors by the Birch Oil Company at Brea, California, and every well shows an increase in daily production over that previously obtained with steam-engine drive. This increase, which is undoubtedly due to the various causes discussed in the foregoing paragraphs, varies from 5 to 41 per cent. Records kept on one of these wells clearly indicate the effect of the more uniform pumping motion which is now obtained. The production over a period of 90 days after the installation of the motor was 10 per cent more than for the previous 90-day period. The maximum production of 380 barrels per day with engine drive was increased to 424 barrels per day with motor drive. One day this well was again operated by steam so that a transformer could be changed, and the production for that day dropped 45 barrels.

TABLE II

Comparative Production With Steam Engine and Electric Drive Under Identical Operating Conditions On the Same Well, Pumping By Engine At Night and By Motor In Day. Burma Oil Company, Singu Field, Upper Burma, India

	August, 1916		September, 1916	
	Barrels	Per Cent	Barrels	Per Cent
Oil pumped by motor	1311	42.5	1310	45.4
Oil pumped by engine	1777	57.5	1587	54.6
	Hours	Per Cent	Hours	Per Cent
Total time motor operation	271	36.5	270	37.5
Total time engine operation	473	63.5	450	62.5
Barrels per hour, motor	4.84	....	4.82	....
Barrels per hour, engine	3.75	....	3.52	....
Increase in production due to motor drive	....	28.5	....	36.0

TABLE III

Increase of Production Obtained With Electric Drive By An Oil Company In the Spindletop Field, Texas, Pumping From a "Power"

	Total Barrels	Barrels Per Day	Barrels Per Well Per Day
Eight wells on steam, January and February, 1918	9346	158.4	19.8
Same eight wells, electric power, March and April, 1918	10791	176.9	22.1
Increase (11.6 per cent)	.....	18.5	2.3

The Burma Oil Company in 1916 operated a well in the Singu field, in Upper Burma, India, by a two-speed oil well motor in the daytime and by steam-engine at night. The engine was used as a countershaft when the motor was running. Both the motor and the engine ran under normal operating conditions. Table II gives the results, which offer unquestionable evidence of the superiority of electric operation.

In the Spindletop field in Texas, an oil company electrified a steam-engine-driven "power," pumping eight wells, and increased their production as shown in Table III. This increase was due partly to the shortening of time lost from shut-downs and delays and partly because of the more uniform pumping speed. If to this were added the amount of oil saved which had been consumed as fuel, the total increase in production would be in the neighborhood of 40 per cent.

Several California men who have had considerable experience with oil well-motors over a number of years are of the opinion that

the more uniform pumping speed has a material effect in establishing better oil channels underground leading to the wells, and in keeping them more nearly free from sand and caving. This can reasonably be believed, and indicates the probability of a longer and more productive life of the wells, as well as less frequent necessity of cleaning them out.

Lower operating expenses.—Enormous waste and losses have long been as much a feature of oil production as large fortunes suddenly accumulated. They still remain so in many places, but to the average man of the fields they are much less evident, though far more general. It is really not so surprising that operating expenses are usually susceptible of extensive reduction, and that the use of oil well motors offers the means of obtaining remarkable results in this respect. This fact is well demonstrated by a few examples selected from numerous available records for pumping on the beam, which are given in Tables IV, V, VI and VII. It must be remembered that the greatly diversified conditions encountered in the oil fields cause a wide variation in the costs of operation, though these check closely for similar conditions. The depth of well, the production, the size of pump, the pumping speed, the distance between wells, the number of wells operated, the gravity of the oil and the amount of water pumped with it all have their influence. Some other results, taking into consideration only those items affected by the change to electric drive, such as fuel, water, labor, maintenance, and electric power, are given below.

The British Consolidated Oil Corporation, Ltd. (now the Indian & Colonial Development Company) made a saving in excess of 22 per cent on 12 wells in the California Midway field.

TABLE IV

Comparative Costs of Gas Engine and Electric Operation of Wells Pumping On the Beam By a Large Oil Company in California

	Gas Engine Per Well Per Day	Electric Motor Per Well Per Day
Labor, including pumpers, engine repair men and electricians	$0.893	$0.589
Fuel or electric power	0.000	0.800
Repairs	0.076	0.024
Lubricating oil, waste, packing and miscellaneous	0.186	0.038
Interest (7 per cent) and depreciation (10 per cent on engines, 4 per cent on motors)	0.509	0.263
Production lost from shut-downs on 50-barrel well, at 40 cents per barrel	0.586	0.014
Totals	$2.250	$1.728

Saving by electricity over gas, per well, per day	$ 0.52
Average saving per well, per year	189.80

Note.—These records were obtained prior to 1917, since when there have been large increases in the cost of several of the items.

TABLE V

Comparative Costs of Steam and Electric Operation of 68 Beam Wells By An Oil Company In California. Depth 800 to 1050 Feet. Gravity of Oil, 14.5 Degrees Beaume

	Total Per Month
Steam—	
Oil fuel at $1.23 per barrel	$17,650.50
Labor	2,527.00
Total	$20,177.50
Electric—	
Power	$ 2,425.00
Labor	1,435.00
Interest, 6 per cent on cost of electrical installation	602.00
Total	$ 4,462.00
Saving by electricity over steam per month	$15,515.50
Average saving per well, per year	$ 2,773.32

TABLE VI

Operating Costs of 15 Steam-Engine-Driven Wells and 14 Motor-Driven Wells Pumping On the Beam During the Same Period On the Same Property in California. Average Depth, 1100 Feet. Gravity of Oil, 15 Degrees Beaume

	Total Per Month
Fifteen Steam Wells—	
Oil fuel at $1.23 per barrel	$1,881.90
Labor, 6 firemen at $4 per 8 hours	720.00
Oil fuel at $1.23 per barrel, used to pump boiler feed water	150.06
Boiler repairs	90.00
Totals	$2,841.96
Cost per well, per year	$2,273.56
Fourteen Electric Wells—	
Power	$ 379.00
Repairs	40.00
Total	$ 419.00
Cost per well, per year	$ 359.14
Saving by electricity over steam, average per well, per year	$1,914.42

Note.—The same pumpers and roustabouts handled both groups of wells. One boiler cleaner was employed for the steam wells and one electrician for the electric wells. Repairs are the average for 5 years operation.

TABLE VII

Comparative Costs of Pumping Eight Beam Wells By Steam and By Electricity In the Midway Field, California. Depth 1000 To 2800 Feet

Steam—	September, 1912	October, 1912
Oil fuel at 50 cents per barrel	$ 469.00	$ 305.50
Labor	448.00	448.00
Water	449.99	457.83
Boiler compound, lubricating oil and grease	30.00	30.00
Totals	$1,396.99	$1,978.74
Average cost per well, per year		$1,978.74

Electric—	January, 1913	February, 1913
Power	$340.00	$329.90
Labor	435.00	383.50
Water	71.00	53.90
Lubricating oils	17.50	17.50
Totals	$863.50	$784.80
Average cost per well, per year		$1,236.22
Saving by electricty over steam, average per well, per year		$742.52

Note.—Since these records were obtained there have been large increases in the cost of several of the items.

In the Coalinga field in California, one oil company installed motors on a group of wells and discarded twelve boilers, thereby making a saving of 63 per cent in operating expenses.

The Salvia Oil Company (formerly the Wabash Oil Company) in the Coalinga field could not produce enough oil, above that used for fuel, to pay operating expenses, and was thereby forced to suspend operations until two enterprising operators, recognizing the possibilities of electric drive, took over the property, installed motors on all the wells, and are now actually paying dividends.

Another company saved 24 per cent on 12 wells, and another 40 per cent on 107 wells.

Fuel.—As oil wells usually require from 60 to 120 kw-hr. per day for all operations asociated with pumping on the beam, reaching in exceptional cases about 200 kw-hr. maximum, it is clear that electric power at prevailing rates is much cheaper than oil fuel or steam operation. It may also be less than gas fuel where the latter has any market value.

Further important points with respect to fuel consumption are that with electricity there is no power consumption when idle, no fuel required to get up steam and no losses from leaky engine valves and piping. Losses from the last cause are well known to be considerable in the oil fields. Their worst feature is that they increase from year to year. Oil men not familiar with electric

power will be interested to know that corresponding electrical transmission losses are not only very low but remain at a fixed percentage throughout the life of the equipment.

Labor.—In Louisiana in the Jennings field there is a lease with 23 steam engine-driven wells on which six firemen and four pumpers are required. Adjoining is another lease with 13 wells electrically operated. Power is generated on the lease. Two men at the power plant and one man at the wells keep things going. The condition is by no means exceptional. In general, one pumper can look after about 8 to 12 gas engines, 10 to 15 steam engines, or 15 to 20 motors, depending upon the distance he has to walk to reach them. One eletcrician can maintain the equipment where several gas engine and boiler repair men would be necessary, and fewer firemen or none at all are required, according to the extent of electrification. This saving in labor has become very important since wages have increased, and in a number of instances has been the deciding factor for making the change to electric drive.

Water.—The cost of either boiler feed water or engine jacket water runs high in many fields because of its scarcity. Even then the quality is bad for the boilers. This expense becomes a thing of the past after motors are put in, the saving alone in many cases being more than the cost of electric power.

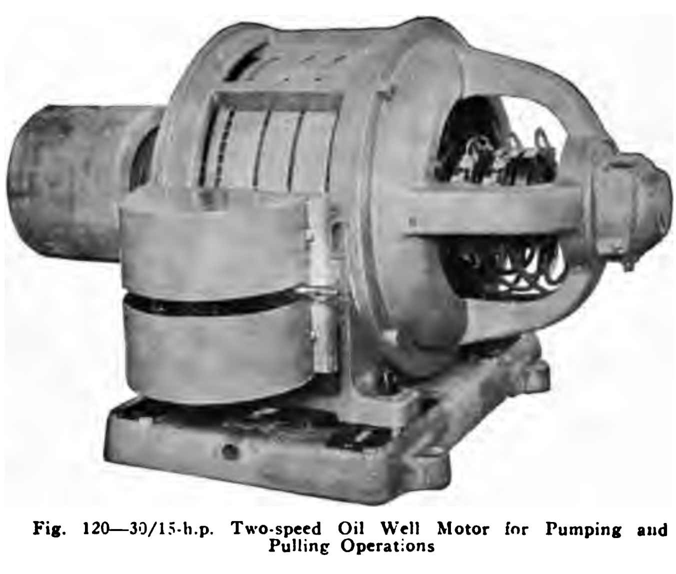


Fig. 120—30/15-h.p. Two-speed Oil Well Motor for Pumping and Pulling Operations

Repairs and lubrication.—There are more than 2000 electrically operated oil wells which have been operating for periods of from 1 to 12 years at which the average repair expense on the electric equipment has not been 1 per cent of the first cost. In comparison, there are several hundred gas engine wells which have operated not more than four or five years, at which the engine maintenance exceeds 11 per cent. For steam engines and boiler plants, 5 per cent is considered a low figure. The saving in expense for boiler tubes and compound, both high because of bad water, and the reduction in the amount of oil necessary for lubrication, contribute largely to the advantage of electric operation.

Only about 20 to 25 per cent of the investment necessary for a stock of repair parts for gas engines is required for motors, both because of the much lower rate of depreciation and of the fact that there are fewer parts to wear out.

Other Advantages

In several more respects motors are a big improvement for oil well work, the following being worthy of mention:

Safety.—Greater safety of operation is obtained, as the motor cannot run away when the rods part.

Explosions are eliminated and the fire risk greatly reduced, thus lowering insurance rates.

Accidents are fewer. One company in the Mid-Continent fields found from an analysis of accidents to its employes that one-third resulted from the necessity of "treading" the flywheels of gas engines to start them. These could not have happened with electric drive.

Reliability and convenience.—As the speed of an oil well motor is practically independent of voltage fluctuations, the motor can always be depended upon to give the same speed on the same controller point for similar load conditions.

A much better motion of cleaning-out tools is produced by a motor than by a gas engine. In this respect it is like a steam engine.

Electric control is very simple, having no reverse lever or clutch pulley. Power is always ready at a turn of the controller, which is handled from the headache-post in the same manner as an engine throttle.

The power consumption of a motor can be quickly and accurately measured, and thus indicates both the condition of the well and the most advantageous operating conditions from the standpoint of cost.

Motor equipments are cleaner and quieter than engines. The belts and motor house can consequently be kept cleaner and there will thus be less rapid deterioration of the rig.

Oil Well Motor Equipments

The success of electric oil well operation has in no small measure been due to the simplicity of the induction motor and its ability to withstand hard usage and to run continuously in exposed locations and under severe conditions. To these considerations must be added the fact that the motors are built with the mechanical strength and overload capacity necessary to withstand oil field service.

Different types of equipments are used for drilling and for pumping. Drilling requires motors of larger capacity than are necessary on producing wells, and the method of control is somewhat different. It is, therefore, advisable in all cases to use separate equipments exclusively for drilling, and, as each well is completed, move the motor and control apparatus to the next new rig and put in a pumping motor as a permanent installation. The pumping equip-

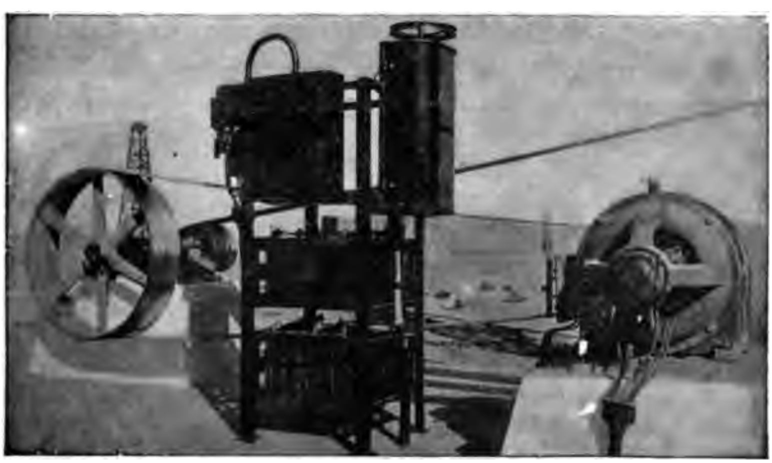


Fig. 121—A Complete 30/15-h.p. Two-speed Oil Well Motor Equipment Installed by a Large Oil Company in Coalinga Field in California. Photograph Made Before Completion of Housing

ments are therefore required in much larger numbers and are of first interest to the producer because of their direct effect on production and costs.

Motors for Pumping, Pulling and Cleaning the Well

Motors for beam wells.—Oil men generally prefer all of the operations in connection with pumping, pulling and cleaning a "beam" well to be performed by one motor, as with engine drive. This is done by the two-speed oil well motor, with both speeds variable (Fig. 120), for which the method of control has been specially designed to satisfy the oil operator in every way. That it does so, and that many of the advantages of this type of equipment cannot be satisfactorily obtained by other means, have been conclusively demonstrated during several years' experience in the fields. The motor is built in three sizes to take care of all conditions of wells. Figs. 121-123 inclusive illustrate modern installations in both California and the Mid-Continent fields, and Fig. 125 shows more clearly a convenient method of mounting the apparatus on skids.

The two-speed feature.—The motor has a wound rotor for variable speed, the latter being obtained by means of a controller and secondary resistor in the same way as with the standard type of varying speed induction motor used in other industrial work. The oil well motor differs from the standard motor, however in having two synchronous speeds, one of these being a low speed suitable for pumping a well, and the other a high speed, double the low speed, for pulling, bailing, "shaking up" and similar work. On the high speed the motor gives the right motion to swing a light set of drilling tools for cleaning-out purposes. The change from the pumping to the pulling speed and vice versa is made by a switch mounted on the motor frame. Both speeds are variable and reversible by the controller and resistor. The controller is always mounted near the motor, as will be seen, for instance, in Fig. 121, and is operated from the headache-post by means of a "telegraph cord" in the same manner as an engine throttle. As has already been mentioned, no reverse lever is used, hence less effort is expended by the operator in controlling the motive power, and he can give better attention to the work at the well.

Deficiency of Y-delta motor.—In the early days of oil well opera-

tion by motors it was recognized that because of the much lower horse power required for pumping than for pulling, an improvement in efficiency would be obtained by using a motor with two different horse power ratings. Such a motor was accordingly produced, and it became known as the "Y-delta" type on account of the method of change in motor connections by a double-throw switch to obtain the two ratings. This motor, however, had only one variable speed at both horse powers, which was a great disadvantage in the fields. For good efficiency, full speed operation was necessary. Naturally this was desired for pumping, hence pulleys were usually selected for that condition. Then when the well was pulled, the speed of the band-wheel was entirely too slow for practical purposes, as it delayed getting the wells back to production, with resulting loss to the producer. Some operators tried running the motor at full speed for pulling, getting a better band-wheel speed by suitably selected pulleys, and then slowing it down for pumping by means of the controller. This not only did not enable them to get all the speed they wanted for pulling or shaking up the well but, worst of all, it immediately resulted in greatly

Fig. 122—A 30/15-h.p., Two-speed Oil Well Motor Showing General Arrangement Used by the Associated Oil Company in the California Fields

increased power bills, thus showing up the greater waste of power when pumping in this inefficient manner.

The expedient was then tried of pumping at full speed with the Y-delta motor and lagging up the bull-wheel shaft to about twice the standard size to obtain high pulling speed. Of course this did not bring up the bailing speed on the sand-reel or enable any shaking-up to be done, and the scheme was abandoned because for relatively deep wells the strain thus put on the bull-rope and gudgeon posts was so great that the former could not be kept tight enough to prevent slipping, and the latter in several instances were actually pulled out.

One other method of adapting the Y-delta motor to these conditions, which was attempted but which failed to solve all difficulties, was that of changing pulleys for pulling. It was such an irksome job that the pulling gang could not be relied upon to continue it, and it always caused loss of production from delay. This method was not successful for shaking-up the well, for the time the motor had been shut down long enough to change the pulley the well had usually sanded up and required an entire pulling job, with more loss in production.

As the Y-delta motor thus failed under all expedients to perform the necessary functions in a satisfactory manner, the two-speed oil well motor with both speeds variable has superseded it, and fulfills all the requirements without any change whatever in rig or pulleys, and with a very economical expenditure of power.

Other features of two-speed motor control.—The equipment is provided with a wall-mounted oil circuit breaker with inverse time limit overload trip coils and under-voltage release. If desired the motor may be protected on the pulling as well as on the pumping duty, for double-wound overload trip coils are used. These coils are so interlocked with the switch on the motor that automatically the proper coil is connected into the circuit. It is thus impossible for the operator to make an error and insert the wrong overload coil for either pumping or pulling duty. The inverse time limit feature gives protection in proportion to the amount of overload, automatically opening the circuit breaker sooner in case of extremely heavy load than when a lighter one is encountered, and thus giving the operator the benefit of the high motor capacity as long as the motor can safely carry it without injurious heating. The under-

voltage release mechanism automatically trips open the oil circuit breaker in case of failure of voltage.

To prevent any accident occurring because of the "telegraph cord" breaking, the equipment may be provided, if desired by the operator, with a push-button mounted on the headache-post. This will open the undervoltage release circuit and thus trip open the oil circuit breaker.

In the manipulation of rods and tubing the quickest reversals and the highest torque of the motor, that is, its greatest ability to pull—are obtained on the intermediate controller points. It is possible to equip the controller with a "current-limit" device that will automatically compel the operator to stop it at the most advantageous point until the motor has gained some speed. This is useful in teaching him how to handle an oil well motor, and furthermore it reduces the average current input while reversing, thus lowering the operating temperature of the motor.

Another refinement used with good results by many oil compan-

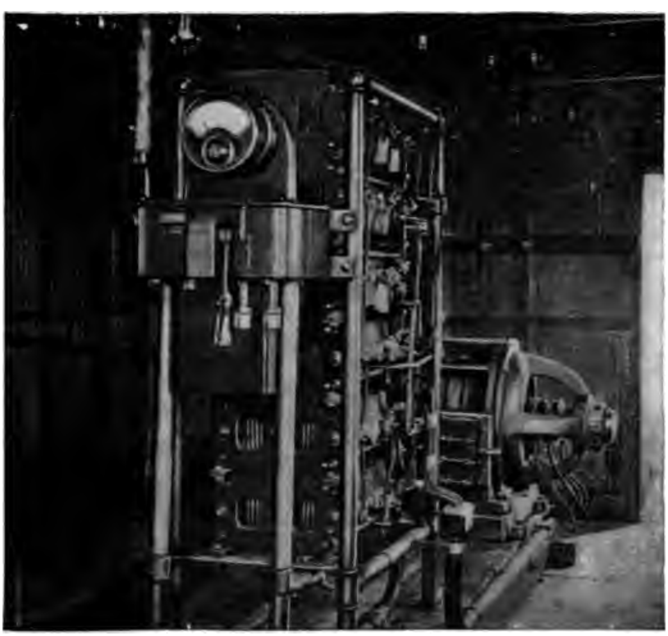


Fig. 123—An Installation by the Carter Oil Co., in the El Dorado Field, Kansas, of a Complete 30/15-h.p., Two-speed Oil Well Motor Equipment

ies is an ammeter mounted on top of the oil circuit breaker and arranged for connection in circuit on pumping duty but not for pulling. This instrument makes it possible to tell whether the walking-beam is perfectly counter-balanced and also gives the operator an indication of when the well begins to sand up.

Motor capacity.—The size of machine for any particular well depends to a large extent upon local conditions and methods of operation, rather than upon the depth of the well alone, and for this reason these things are necessarily taken into consideration in every case. For instance, the heating of the motor on heavy work does not depend so much upon the torque required as it does upon the frequency of reversing the motor, and this is largely governed by the operating methods, which vary in different fields.

In general, experience has shown that a 30-h.p. motor rated 15 h.p. on the pumping speed (Fig. 120) is the size suitable for the great majority of wells. Sometimes where the depth is under 2000 feet or the duty is light a 25/10-h.p. motor will do the work, but on any lease requiring a 30/15-h.p. machine it is advisable to use this size on all wells for the sake of standardization and to keep the repair part stock at a minimum. Very deep wells may require a 50/20-h.p. motor.

The power input for pumping will vary from day to day and even from hour to hour, and may increase considerably in a short time when the well is sanding up. For this reason the motors are given liberal ratings for pumping. For handling rods and tubing the motor may be required to deliver very high power for short periods, especially in emergencies and on some of the special operations, swabbing for example, which are occasionally necessary to maintain the well as a good producer. Although such loads are several times greater than the pumping load, they are easily handled by these motors because of their enormous overload capacity on high speed, this being from 3½ to 5 times the rating for pulling, or 7 to 10 times the rating for pumping.

Separate motors for each duty.—A few operators have placed a motor of small capacity at each well for pumping only, and use a portable motor (Fig. 127) or motor-driven hoist (Fig. 130) for pulling and bailing. This can be done, if desired, where conditions do not require very frequent pulling of the wells ,and their spacing or the character of the country make pumping by jack power imprac-

ticable. In such cases squirrel-cage or varying-speed motors with control for reversing are used for pumping and a high torque motor with variable speed is necessary for pulling.

Usually, however, the cost of the portable hoist, with wagon and team or a truck, together with the expense for necessary plug connections for each well, bring the investment up close to that for a two-speed oil well motor at every well.

Mechanical arrangement for beam wells.—The use of a motor belted to a countershaft, the latter belted to the band wheel, has become universally standard practice for beam-wells, and all modern equipments are are thus arranged. In the case of wells having a steam or gas engine already installed but of no further use, the engine has often been used as a countershaft, disconnecting the connecting-rod and putting pulleys on the shaft. A cheap and substantial pulley has been made by lagging the flywheel with wooden sections bolted to it.

The use of back-geared motors ,tried several years ago, is no longer considered desirable by oil men, and the arrangement has been discarded in present practice.

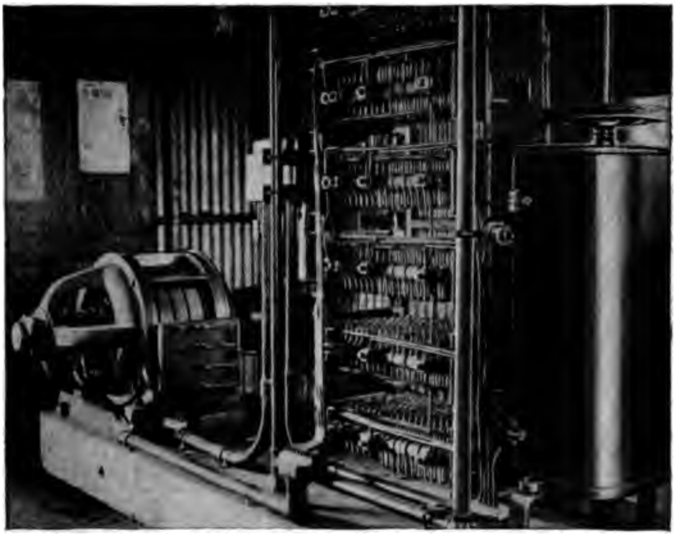


Fig. 124.—One of the 30/15-h.p., Two speed Oil Well Motor Equipments of the Empire Gas and Fuel Co., in the El Dorado Field, Kansas.

Counterbalancing beam-wells.—The ease of measuring the power impút to an electric equipment by a meter has directed attention to the reduction in the amount of power required to pump a well obtained by counterbalancing the weight of the rods on the beam. This relieves the motor of the necessity of hoisting the full weight of the rods on each stroke. The reduction in power is considerable, varying with local conditions from 8 to 22 per cent, and averaging about 15 per cent. Fuel consumption can therefore be materially decreased by installing a counterbalance on each beam-well, regardless of the method of drive.

Rod breakage is another condition which is being improved by counterbalancing. The uneven motion of the engine, particularly of the gas engine, due to its inherent method of action as well as to its unbalanced load, causes the rods to be picked up with a jerk, and the vibration thus produced is the cause of much of the rod breakage with which every producer contends. Counterbalancing the beam has proved to be the means of greatly reducing this in many instances in the California and Mid-Continent fields, and is thus resulting in a direct saving in oil production ordinarily lost by the shut downs occasioned by breakage.

Fig. 125—This Method of Mounting the Entire Electric Equipment on Skids is Used Extensively for Oil Wells in the Mid-Continent Fields

The counterbalance is believed to be indirectly a valuable means of reducing the amount of waste emulsion in wells having considerable water. It is generally recognized that the emulsion is caused by the churning action produced by damaged or leaking sups and valves, and this damage is no doubt largely due to the jerks and vibration mentioned above. The value of the counterbalance in reducing this content therefore lies in its ability to smooth out the pumping motion.

The use of a counterbalance is recommended on every motor-driven rig. Its cost is nominal. A common type is illustrated in Fig. 129 but the best of the various types in use is the one in which the weight itself is a concrete block, preferably made in several sections, and supported from an extension of the walking-beam by a stirrup which may be moved to change the leverage and thus obtain the best equipment. Suitable guides are used to prevent the block of concrete from swinging from side to side. This method of support makes the weight 100 per cent effective, which is not the case with counterbalances consisting of a heavy weighted piece of timber with one end resting on a post in the ground.

Motors for jack-well pumping.—Wells pumped by jacks and operated in groups from a central "power" can be electrified at a comparatively low cost per well.

A countershaft is placed between the motor and the "power" and usually carries a friction clutch for starting the wells after the motor has been brought up to full speed. The use of such a clutch on every installation is desirable, as it relieves the motor of heavy starting duty and thus enables a standard squirrel-cage motor to be used, whereas otherwise it would be best to put in a slip-ring motor to make it possible to start the wells slowly and thus prevent breaking the shackle rods. The complete equipment is very simple. Fig. 128 shows an installation of this type. When the wells are cleaned a portable hoisting equipment is employed, such as in Fig. 130.

The power required for pumping wells by this method is affected not only by variations in the depth of the wells, the height to which the fluid rises in the wells, the gravity of the oil, the diameter of tubing, the speed of pumping, and the general condition of the wells with respect to sand, gas and water content, but also depends considerably upon how well the wells are balanced against each other. Therefore, the use of an ammeter in the motor circuit is desirable to tell this exactly.

Motors for Drilling

Cable-tool method.—The standard type of varying-speed induction motor with wound rotor (Fig. 135) is the best machine for drilling, the required range in speed being obtained by resistance in the rotor circuit, as with the pumping motor, but a two-speed feature is neither necessary nor desirable. An auxiliary controller provided in addition to the main controller gives the very fine adjustment of speed required in cable drilling to make the movement of the beam accord with the natural period of vibration of the drilling line.

The main controller alone gives ten points of control; the auxiliary controller cuts in eight additional control points between any adjacent points on the main controller. This results in a total of 88 points, which are sufficient to obtain the correct speed at all times without danger of deadening the movement of the drilling bit and endangering the line and beam by overstraining them.

Fig. 127—20-h.p., Portable Motor Equipment for Pulling Oil Wells at the Badger Oil Co., Hosston, La.

The two controllers are operated independently from the headache-post and govern both forward and reverse operation.

Other methods of obtaining variable speed by special designs have been tried on this work, but the advantages gained, if any, were not sufficient to warrant the increased cost of apparatus or the additional attention and expense necessary to maintain it in good operating condition. Simplicity of operation is a strong point in favor of the equipment now standardized for this service, since the various drilling operations follow so closely upon each other that the driller cannot be put to the inconveniences of throwing switches

or shifting clutches each time, particularly when entirely satisfactory results can be obtained without going to such trouble.

In cable drilling the beam must overspeed and allow a "free drop" of the tools on the down-stroke to get the most effective blow, and to accomplish this the motor must slow down on the up-stroke and speed up on the down-stroke. This characteristic is very satisfactorily obtained with the drilling motor by so proportioning the pulleys that some secondary resistance will be in circuit when the motor is operating at the correct drilling speed.

With electric drilling it is customary to insert an ammeter in the motor circuit and mount it where it can be easily seen by the driller. This gives him an accurate indication of the amount of strain he is putting on his casing.

Fig. 128—A 35-h.p. Motor-driven Bandwheel "Power" for Pumping 32 Wells in Kansas

Rotary method.—The same type of motor used in cable drilling is well suited for driving the rotary table and draw-works and also the slush pump. Variable speed is needed in both cases, and

although a single controller for each motor will prove satisfactory, some operators have put in a standard cable-tool outfit for the rotary drive so that it would be available to finish up the well with cable-tools when the oil sand was reached.

Motor capacity for either drilling method.—The power required in drilling an oil well varies considerably for the numerous operations. Drilling itself is a fairly steady load on the motor, while the other work, particularly the manipulation of casing, is heavy and

Fig. 129.—The Type of Counterbalance on this Motor-driven Well of the Empire Gas & Fuel Co. in the El Dorado Field, Kansas, is Frequently Employed

very intermittent in character. Drilling motors can exert a very heavy torque or pulling effort, and their ability to do so in an emergency is often the means of freeing a string of "frozen" casing which might otherwise have to be "landed" in the hole, thus necessitating the drilling being resumed with a smaller string. The high torque capacity is of particular value in such operations as "spudding" casing and loosening stuck tools, and in rotary drilling it is a necessity in handling the drill pipe as well as the casing.

For the standard size of cable-tool and rotary rigs and tools now used in the United States, a 75-h.p. machine has been found to have sufficient capacity for all requirements in drilling wells much over 2000 feet in depth. For more moderate depths 50-h.p. may be sufficient. Rotary rigs require a 100-h.p. motor where the rotary table is operated at a maximum speed in excess of 80 r.p.m. If the sprockets are so proportioned that this speed cannot be exceeded, which compares favorably with the usual conditions with steam-engine drive, a 75-h.p. motor will successfully handle the work. Local conditions must be considered in any specific case. In some foreign fields motors as large as 150 h.p. are used because of the different types of rig and methods of operation employed.

Fig. 130—Portable Electric Hoist Used for Pulling and Cleaning Jack-wells in the Kern River Field, California

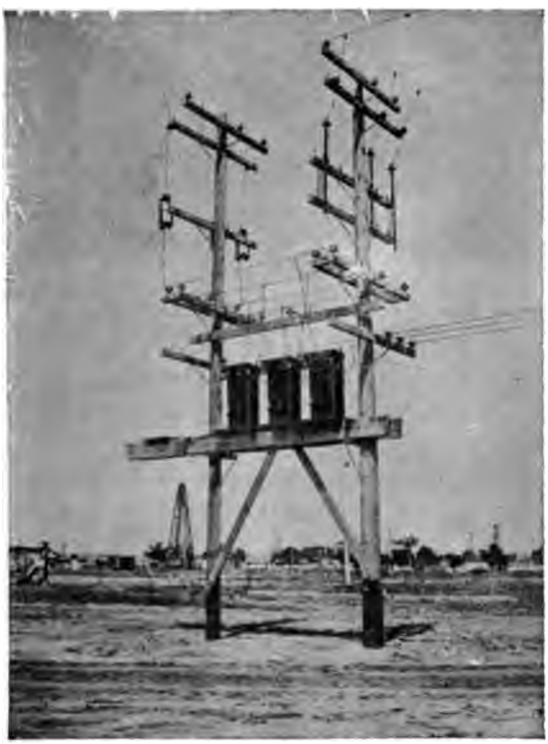


Fig. 131.—A Typical Transformer Installation Made by the Empire Gas & Fuel Co., for Oil Well Pumping in the El Dorado Field, Kansas. The Bank Consists of Three 25-kv-a Units, Stepping the Voltage Down from 1200 to 440

Fig. 132.—The Deepest Electrically Drilled Oil Well in the World. This is the "Anita A" Well of the Shell Co., of California Located Near Turnbull Canyon in Los Angeles County. The Depth on June 23, 1920, was 4560 Feet.

On a rotary rig it is an advantage to use on the slush-pump a motor which is a duplicate of that for drilling, as fewer spare parts are then required.

Mechanical arrangement. — The use of a belted countershaft, as shown in Fig. 121 is the accepted standard method of drive for cable-tool drilling as well as for pumping.

On account of the heavy strains to which the equipment is subjected, back-geared motors cannot be recommended for this service.

A few installations have been tried using a two-speed or three-speed change-gear countershaft to obtain more economical speed variation, but they have all been discarded because of their rapid depreciation under the severe service. Furthermore, the operators generally failed to make use of the device because of the time and trouble involved. Experience has shown that the plain countershaft drive and the main auxiliary control are satisfactory in giving all necessary speed changes.

For rotary drilling also a countershaft is needed. It is advisable to use chain drive between this and the rig as this can be better adapted to the usual mechanical arrangement of the draw-works, but the motor should be belted to the counter shaft so that it can be used for cable-tool work if necessary.

In order to facilitate moving the drilling motor from one rig to

Fig. 133.—This Group of Wells in the California Midway Field Has Been Electrically Operated for Several Years by the Fuel Oil Dept. of the Southern Pacific R. R.

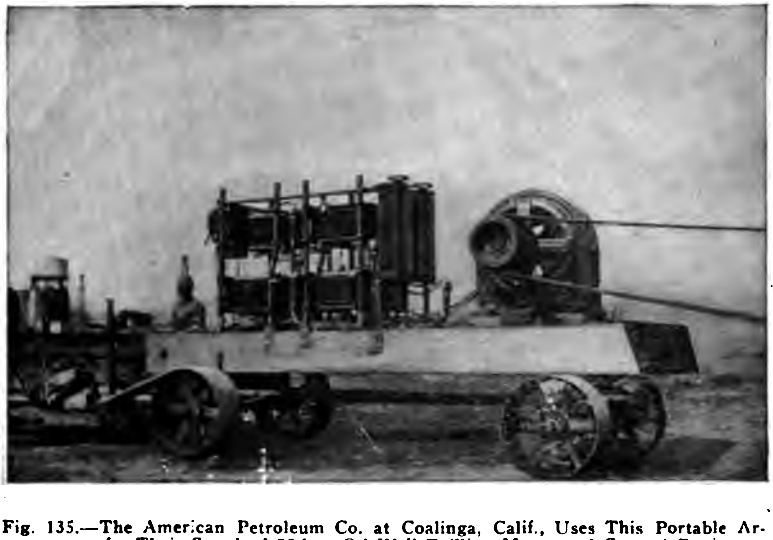


Fig. 135.—The American Petroleum Co. at Coalinga, Calif., Uses This Portable Arrangement for Their Standard 75-h.p Oil Well Drilling Motor and Control Equipment

another, a number of the operators have mounted the equipment on a heavy wooden block provided with axles so that wheels may be put on when it is moved. In one or two instances the wheels are not removed when the motor is put in drilling service, but the truck is held in position by means of struts. (See Figs. 135 and 136.)

Transformers.—If an oil company purchases its own transformers, the cost of electrification is of course lower when an entire group of wells is equipped with motors, as one bank of transformers can be put in to supply power for all. Less transformer capacity is then needed, the only enough extra capacity must be put in for pulling and cleaning one or two wells simultaneously. If separate banks of transformers were used for each well they would all need to be sufficiently large for pulling and cleaning duty. The number of wells that can be operated from a single bank will depend entirely upon their relative grouping and the amount of power required to pump each one.

For drilling work it is the best practice to use a separate bank of transformers for each motor. They may be mounted on the ground near the motor ,thus shortening the heavy secondary lines and making it more convenient to move the transformers from rig to rig, or the method illustrated in Fig. 136 may be used.

If it is preferred to mount them on poles, a good method is shown

Fig. 136.—The Bank of Transformers Used for the Drilling Motors Shown in Fig. 135.

in Fig. 131. This is customary for permanent installations and enables the transformers to be handled readily from a truck directly underneath, thus facilitating repairs and replacements. High-voltage lines can thus be kept well away from the derrick, rigs and buildings.

Comparative Costs of Developing Electrical Power for Pumping

By S. G. GASSAWAY[1]

There are three common methods of pumping in the field; namely, by steam engines, gas engines supplied with natural gas and by electric motors. The power for the steam engines is usually generated from natural gas obtained on the lease, or if this is lacking, by burning under the boilers, a part of the oil produced. With motors, power may be purchased as in the case of the California fields from the large hydroelectric power transmission systems, or generated on the lease by steam, gas or oil engines. This article considers five schemes of pumping the wells both "on the beam" and by "jacks."

A. Installing electric motors at the wells and jacks.

B. Installing gas engines at the wells and jacks, and small gas engine driven plant for lighting.

C. Generating plant using gas engines.

D. Generating plant using condensing steam turbines.

E. Steam engines at wells and jacks, including boilers.

We have also prepared four propositions which give the operating costs.

V. When purchasing power with equipment A.

W. Operating with individual gas engines, no power plant, equipment B.

X. Generating power with plant C and motors installed on wells and jacks, equipment A.

Y. Generating power with plant D with motors installed on wells and jacks, equipment A.

Z. Steam engines at wells using oil for generating fuel, equipment E.

The figures are based on the average of a number of operating results obtained on plants in the oilfields and elsewhere.

To the end that the figures given might be applicable to as

[1]Published by permission of General Electric Review.

many different field conditions as possible the conditions as given below have been taken as best suited to meet these requirements. Comparatively deep wells (2700-3600 feet) with a naverage production (80 barrels) have been taken as representing the more severe and expensive production conditions and shallow "jack" wells as representing the other extreme, as representing cheap production.

There may be some questions as to the amount charged to lost production because of shut downs. This is a question on which there are about as many differences of opinion as there are operators. All operators, however, are agreed that the more hours the beam is kept bobbing up and down the larger will be the net production at the end of the year. Therefore, if the wells are shut down because of repairs or other interruptions it is to be expected that the yearly production will fall off correspondingly. Account has been taken that these shut downs do not occur in one continuous period, but that the total shut down is made up of many shut downs of varying length throughout the year. Also, as there will be a "head" of oil on the wells when they are started up, the loss in production for a short shut down will not be as great as for a long shut down. To be on the safe side, no lost production is charged to the jack wells, as 16 hours a year shut down with motor drive would not actually result in any lost production, although with the larger shut downs due to gas engines a loss in production would result.

There are more than 2000 electrically operated oil wells which have been operating for periods of from 1 to 11 years in which the repair expense has not equalled 1 per cent of the first cost. Likewise, there are several hundred gas engine wells which have operated not more than 4 or 5 years in which the maintenance exceeds 11 per cent. A maintenance of 2 per cent on electric motors and 9 per cent on the gas engines installed at the wells has been assumed. A maintenance charge of 6 per cent is allowed on the gas engines and electric machinery in the power plant as there will be standby units and the plant is under more expert supervision than in the field. Likewise for the turbine driven plant, 2 per cent for maintenance is allowed. For steam engines and boiler plants in Z, 5 per cent is allowed for maintenance.

There may be some difference of opinion as to the earning ca-

pacity of money invested in new wells. This article assumes that the money invested in new wells will at least bring a net return, after all operating expenses have been paid, of 20 per cent.

The conditions taken are as follows:

Connected Load:

30 wells "on beam"—depth 2700-3600 ft.
65 wells on 4 "jack powers"—average depth 550 ft.
Size tubing, beam wells—2½ in., Jack wells—2 in.
Size pump, beam wells—2½ in., Jack wells—2 in.
Gravity oil 33° B. Average production, beam wells—80 bbls.

Lighting:

30 kw. for 3 hours.
20 kw. for 9 hours.

Initial Unit Cost Installation at Wells ([2])

Beam Wells—including engine and motor house and all equipment within the house except band-wheel belt, lease piping for gas and water and steam, water tank, electric transmission line on lease and boiler plant in case of steam engines—all installed ready to operate

Steam Engines	$ 1,400.00
Electric motors	1,350.00
Gas engines	1,900.00

Jack Power Plants—17 wells each

With 30 horse power gas engine including building, jerk lines to the derrick (but not including pumper jack at wells), and gas and water lines	$ 6,000.00
Ditto with 25 horse power electric motor with transmission line on lease	$ 5,100.00
Ditto with 30 horsepower steam engine and boiler	$ 6,000.00

Power Demand

Assuming daily load as follows—
29 pumping wells, beam.
1 pulling well, beam.
4 jack powers.
Lighting load as above.
Average power demand will be 377 h.p.
Peak—425 h.p.
This is equal to 280 kw. and 315 kw. respectively.

INSTALLATION COSTS AT WELLS

A. **Electric:**

30 wells at $1,350.00	$ 40,500.00
4 jack plants at $5,100.00	20,400.00
	$ 60,900.00

B. **Gas Engine:**

30 wells at $1,900.00	$ 57,000.00
4 jack plants at $6,000.00	24,000.00
	$ 81,000.00
30 kw. generating plant for lights	4,500.00
	$ 85,500.00

(Continued on next page.)

INSTALLATION COSTS AT WELLS.—Continued

C. **Generating Plant:**

3–150 kw. 250 h.p. gas engine driven generators with necessary switchboard, step-up station transformers and distribution transformers for power, with high tension distribution lines on lease, and necessary station building—installed ready to operate	$ 74,500.00

D. **Generating Plant:**

Ditto except 2–300 kw. Curtis turbine driven generators operating condensing complete with boilers arranged for gas or oil firing, and necessary jet type condensing apparatus and complete spray cooling system with concrete pond—installed ready to operate	$ 58,800.00

E. **Steam Engine:**

30 wells at $1,400.00	$ 42,000.00
4 jack plants at $6,000.00	24,000.00
	$ 66,000.00
30 kw. generating plant for lights	$ 3,800.00
	$ 69,800.00

OPERATING DATA

V. **Purchasing Power** at 1 cent per kilowatt hour.

Operating Cost:	Per Year
6 pumpers at $105.00 mo. each	$ 7,560.00
1–electrician at $125.00 mo	1,500.00
Lubricating oil	75.00
Interest —6. per cent Sinking fund —7. per cent Maintenance —2. per cent Insurance and taxes—1. per cent 16 per cent ×	
$60,900.00 (A)	9,744.00
Power bill 2,452,800 kw. hours at 1 cent	24,528.00
Lost production on 30 beam wells, producing 80 bbls. per day each, due to shut down of 16 hours per year due to power failures and all electrical troubles—10 bbls. loss per per well per year at $1.00 per bbl	300.00
Total operating expense	$ 43,707.00

W. **Individual Gas Engines:**

Operating Cost:	Per Year
8 pumpers at $105.00 per mo	$ 10,080.00
1 Electrician to operate light plant—$125.00 per mo	1,500.00
2 gas engine repair men 1 at $150.00 per mo. 1 at $105.00 per mo	3,060.00

(Continued on next page.)

OPERATING DATA.—Continued

Interest —6. per cent
Sinking fund —7. per cent
Maintenance —9 per cent
Insurance and taxes—1. per cent

23 per cent × $85,500.00 (B)	19,665.00
Lubricating Oil	2,040.00
Lost production on 30 beam wells, producing 85 bbl. per day each due to 210 hours per year (average 4 hours per week) shut down because of gas engine, mixture and gas supply troubles and time for repairs—400 bbls. loss per well per year at $1.00 bbl.	$ 12,000.00
Earning power of $24,600. Difference cost A and B if invested in new wells at 20 per cent net	4,920.00
Total Cost Operation	$ 53,265.00

To operate will require 219,000 cu. ft. gas daily with flow to carry over peak loads at rate of 244,000 cu. ft. day.

X. **Generating Power with Gas Plant C**

Cost Operating Equipment A same as operating cost V except no power bill	$ 19,179.00

Cost Operating Plant (C)

Interest —6. per cent
Sinking fund —7. per cent
Maintenance —6. per cent
Insurance and taxes—1. per cent

20 per cent × $74,500.00 (C)	14,900.00
Labor—2 engineers; 3 oilers and helpers; 1 machinist	10,000.00
Lubricating oil and supplies	900.00
Earning power of $74,500.00 Cost of power plant C, if invested in news wells—20 per cent net	14,900.00
This plant will require 108,000 cu. ft. gas per day.	$ 59,879.00

Y. **Generating Power with Steam Plant D**

Cost Operating Equipment A same as operating cost V except no power bill	$ 19,179.00

Cost Operating Plant D

Interest —6. per cent
Sinking fund —7. per cent
Maintenance —2. per cent
Insurance and taxes—1. per cent

16 per cent × $58,000 (D)	$ 9,408.00
Labor same as Plant X	10,000.00
Lubricating Oil and Supplies	300.00
Earning power of $58,800. Cost of Plant D, if invested in new wells 20 per cent net	11,760.00
Total Cost	$ 50,647.00

This Plant will require 166,000 cu. ft. gas per day.

(Continued on next page.)

OPERATING DATA—Continued

Z. Steam Engines—oil fuel	
8 pumpers at $105.00 mo.	$ 10,080.00
1 Electrician to operate light plant—$125.00 mo.	1,500.00
8 firemen for boiler plants (¹) at $105.00 mo.	10,080.00
Lubricating Oil	1,200.00
3 boiler repair men	4,200.00
Interest —6. per cent	
Sinking fund —7. per cent	
Maintenance —5. per cent	
Insurance and taxes—1. per cent	
19 per cent × $69,800 (E)	13,262.00
Lost production on 30 beam wells due to engine and boiler troubles, 10 bbls per well per year at $1.00 per bbl	300.00
Earning power of $8,900 (difference cost A and E) if invested in new wells at 20 per cent net	1,780.00
Selling value of 98,100 bbls. fuel oil at $1.00 bbl	98,100.00
Total Operating Cost	$140,502.00

RECAPITULATION

	Cost Equipment at wells	Cost Power Station Equipment	Yearly Operating Cost
	A		V
Electric Motors, Power purchased at 1 cent kilowatt hour	$60,900.00	—	$ 43,707.00
	A	D	Y
Electric Motors, Power generated by steam turbines	$60,900.00	$58,800.00	$ 50,647.00
	B		W
Gas Engines	$85,500.00	—	$ 53,265.00
	A	C	X
Electric Motors, Power generated by gas engines	$60,900.00	$74,500.00	$ 59,879.00
	E		Z
Steam engines at wells, including bailer plants burning oil	$69,800.00	—	$140,502.00

Comparative Costs of Developing Power for Pumping in the Oil Fields Revised for Conditions in the Mid-Continent Fields[1]

The complete analysis in the accompanying reprint of Mr. S. G. Gassaway's article entitled "Comparative Costs of Developing Power for Pumping in the Oil Fields," was based on the approximate average conditions met in the California fields, and should be somewhat modified for Oklahoma and Kansas conditions, in accordance with the following recommendations:

[1]Comment by W. G. Taylor. By permission of General Electric Co.

(a) Increase power rate to 2 cents.

(b) Increase value of lost production to $2.00 per barrel.

(c) Increase amount of lost production with gas-engine drive to 550 barrels per well per year (under "W") because of more shut-downs, due to cold winter weather, than in California.

(d) Increase the earning power of money invested in new wells to 40 per cent. There are two reasons for this: First, the cost of a well in Oklahoma or Kansas in about one-half of that in California; second, the value of the production is twice that of California. In other words, with the same investment twice as many wells can be put down, and if their production per well averages only one-half that of California wells, the value will still be twice the value of California production.

A revised recapitulation based on these changes is as follows:

	Cost Equipment at Wells	Cost Power Station Equipment	Yearly Operating Cost
Electric motors, power generated by steam turbines	$60,900	$58,800	$ 62,707
Electric motors, power purchased at 2 cents per kwh	60,900	....	68,535
Electric motors, power generated by gas engines	60,900	74,500	75,079
Gas engines	85,500	....	79,185
Steam engines at wells including boiler plants burning oil	69,800	....	240,682

Possibilities of Diesel Engine Power Plants

Coastal fields.—On medium large properties in the Gulf Coast field it is possible to operate with electricity far more economically than with steam. The operators are beginning to realize this and in the Goose Creek and Spindletop fields a considerable amount of electrical equipment has been installed. The best way to show the savings that can be effected with electric power is to take into consideration a set of hypothetical conditions. Take, for instance, a property of 250 acres on which there are located 90 producing wells of average depth. We will suppose that this property is now being operated with steam power. Ten of the wells are isolated, or make considerable amounts of water, and hence are operated with standard rigs. The other 80 wells are operated by jack lines from three band wheel pumping powers. The powers are run with combined steam and gas engines and steam is used for pulling rods and

tubing at the wells, for bailing, for running standard rigs, for operating steam pumps, and for treating oil. Steam is supplied from one central station with 700 boiler horse-power and one substation with 200 boiler horsepower. The reader can imagine the number of feet of steam lines necessary to supply steam at the various places where it is needed on the property. We will consider that the production on this property is 1300 barrels per day and that 12 per cent of this, or 156 barrels of oil, is used for fuel at the boiler stations. We will further consider the gas supply as little more than sufficient for running two 50 horsepower gas engines located at two of the pumping powers.

It is proposed to do away with all steam engines, steam pumps and gas engines on the property, and to treat oil with steam, using one small boiler, same to be fired with the gas saved by doing away with the gas engines. For steam engines electric motors are to be substituted. In place of steam pumps tail pumps ,mounted on the pitman end of walking beams ,and rod line pumps operated by jack lines, are to be used.

Power for running motors is to be generated by a 260 K. W. generator direct connected to a 300-horsepower Diesel engine. It must be borne in mind that there is a considerable difference between the low-compression crude oil or semi-Diesel engine in small horsepowers and the high-compression type of true Diesel engine made in sizes of 100 horsepower and upwards. The latter has been perfected to the point where it is absolutely reliable in every respect.

The better makes of Diesel engines will burn any kind of fuel and are guaranteed to operate on full load with a fuel consumption not to exceed 0.5 pounds per brake horsepower hour. In other words, a 300-horsepower engine would be guaranteed not to use over 10.6 barrels of 19 degrees Beaume gravity oil per 24-hour day when running at full load. In actual practice some of these engines on full load operate with a fuel consumption as low as 0.42 pounds per brake horsepower hour.

Providing that there is enough gas available on the property under consideration for generating sufficient steam to treat the oil the total fuel consumption per day would be reduced from around 156 barrels to 10.6 barrels by installing the electrical equipment. In other words, the fuel consumption would be reduced from 12 per cent to 0.81 per cent of the total production on the property.

With the equipment above referred to the following expensive items of upkeep would be done away with:

1. Repairs to boilers, such as replacing flues, targets, etc.
2. Repairs to gas engine.
3. Repairs to steam lines.
4. Upkeep of boiler feed water system and trouble with boiler water.

It is important to bear in mind that the depreciation on electrical equipment is only about one-half what it is for steam equipment.

The saving per year of the electrical equipment over the steam would be somewhat as follows:

52,925 barrels of fuel oil at $3.00	$158,775.00
Maintenance saving—	
Elimination of one boiler station, hence saving in labor of	5,512.50
Estimated saving per year in repairs, renewals, lubricants, etc.	1,300.00
Total	$165,587.50

The cost of installing the proposed electrical equipment is estimated to be about as follows:

One 300-horsepower Diesel engine.	
One 260 K. W. Generator, 2200 volts.	
Thirteen 8/25 horsepower, two speed motors for operating standard rigs, portable hoisting engines, machine shop, etc.	
Three 50-horsepower motors for operating pumping powers.	
Miscellaneous transformers, switchboards, exciter, etc., etc.	
Total	$59,400.00
Installation of above, including all foundations, buildings, poles, wiring, etc.	22,000.00
Total	$81,400.00
Salvage value of equipment to be replaced	8,300.00
Net cost of new equipment	$73,100.00

From the above it can be seen that the electrical equipment for this property will pay for itself in about five or six months' time. As the coastal crudes get scarcer equipment of this kind will forge to the front very rapidly.

Comparison of Diesel Engines and Steam Turbines for Operating Electric Generating Equipment

Throughout the southwest oil operators are beginning to see the benefits of electrification of properties. In many cases it is necessary for these companies to generate their own power as there

is very little power for sale in the fields. In discussing the question of central generating stations the question immediately arises as to whether it would be cheaper to install Diesel oil engine driven generators or steam turbine generators. In general it can be said that in plants of around 1000 h. p. the fuel consumption in Diesel engine driven plants will be only about one-third of what it is in steam turbine driven plants. On the other hand the oil engine installation will cost almost twice that of a turbine driven station and the depreciation per month on the oil engine station will be almost twice as high. Oil engines work very nicely on steady, constant loads but they are at a great disadvantage when handling variable loads. They are entirely incapable of overload. Steam turbines, are considerably less subject to mechanical troubles than oil engines and hence give more constant service. They handle a fluctuating load very successfully and are subject to overload. Therefore it is not necessary to have as large an installation, horsepower for horsepower, of turbines as of oil engines.

Comparison of cost.—A plant designed for 900 kilowatt duty will cost (1920) about $272.00 per kilowatt, installed for the Diesel engine drive and $163.00 per kilowatt, installed, for the steam turbine driven installation. This might be detailed as follows:

Comparison of Cost of Diesel Engine Driven and Turbine Driven Central Station

	Steam Turbine Plant	Diesel Engine Plant
Building	$ 17,500.00	$ 13,500.00
Foundations	9,200.00	9,000.00
Three 480-h.p. oil engines, installed		165,000.00
Three 300-h.p. turbines, installed	44,000.00	
Three 300-hp generators, installed		30,000.00
Boilers	26,800.00	
Steam auxiliaries	27,000.00	
Piping, pumps, etc	6,000.00	4,500.00
Fuel system	1,100.00	3,000.00
Switchboard and wiring	12,000.00	12,000.00
Spares	900.00	900.00
Miscellaneous	3,500.00	7,000.00
Totals	$148,000.00	$244,900.00
Cost per k. w. installed	163.33	272.11

It is figured that a 1500 kilowatt station in the Gulf Coast section will cost about $430,000.00 for a Diesel engine drive and $250,000.00 for a steam turbine drive.

Fuel consumption calculation.—A full Diesel oil engine which

guarantees to deliver a brake horsepower on less than 0.47 pounds of 20 degrees Beaume oil (7.781 pounds per gallon) will deliver 10.52 kilowatt hours at the generator per gallon of oil. This is equal to about 9½ kilowatt hours per gallon of oil at the switchboard.

A steam turbine which guarantees to deliver a kilowatt hour on 20 pounds of steam will deliver 4.24 kilowatt hours on one gallon of 20 degrees Beaume oil using steam from a boiler which evaporates 12 pounds of water to steam per pound of oil. This is equal to about 3½kilowatt hours per gallon of oil on the switchboard.

The 900 kilowatt installation above referred to would operate on about 700 barrels of oil per month in a Diesel engine driven station and 2000 barrels per month for a turbine driven station. At $3.00 per barrel for fuel this would make a saving of $3,900.00 per month in favor of the Diesel engine driven station.

A 1500 kilowatt station running at about two-thirds load should not use more than 1500 barrels per month with oil engine drive and approximately 3500 barrels per month with steam tubing drive. This gives a saving of 2000 barrels per month in favor of the oil engine drive.

Electric Power Required for Various Oilfield Operations

A paper on "Motor Equipments for the Recovery of Petroleum" by W. G. Taylor, presented at the annual convention of the American Institute of Electrical Engineers (1916) contains data regarding the amount of power consumed in various oilfield operations. Handling the casing is recognized as the operation that makes the

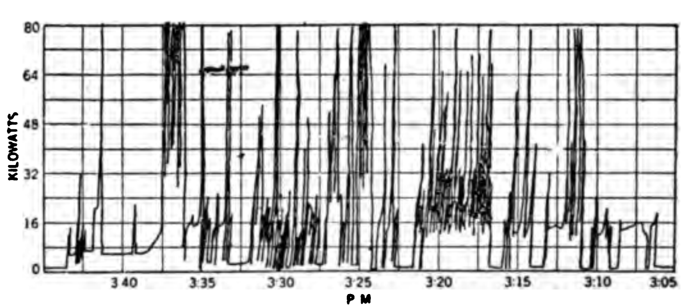


Fig. 157—Curve of Power Demand in Handling Casing

heaviest demand on the prime mover, whether steam engine or electric motor. Fig. 137 shows graphically the variations in the power required. The motor in question was rated at 50 h. p. The character of bailing and drilling requirements is shown in Fig. 138. It should be remembered that both these diagrams read from right to left. The total consumption of power during the drilling of any given well will vary approximately as the square of the depth of the well. From actual records, an 800-foot well required about 3000 kilowatt-hours, while a well 2060 feet deep required about 37,000 kilowatt-hours. Slip-ring induction motors are generally used for drilling. A 50-h.p. is usually employed for wells up to 2500 feet deep, but a 75-h.p. motor is sometimes needed.

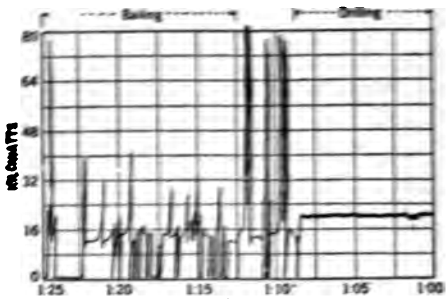


Fig. 138—Curve of Power Demand in Drilling and Bailing

While electric motors are used to some extent for drilling with cable tools, and even for drilling with a rotary outfit, most of the motors in the oilfields are used on producing wells for pumping, cleaning, pulling tubing, etc. The size of motor needed for pumping is determined by general practice, rather than by theoretical considerations. The following is a summary of records from over 200 wells in the California fields:

Depth of wells	900 to 3100 ft., average 1430 ft.
Length of stroke	29 to 32 in.
Strokes per minute	20 to 30, average 24
Diameter of tubing	3 in.
Power required	1 to 5 hp., average 3.5 to 4 hp.

Exceptional wells in California have required as high as 16 to 17 hp. at times. In Louisiana some heavy pumping wells have been encountered, one in the Evangeline field requiring the following:

Depth, ft.	1000
Length of stroke, in.	30.5
Strokes per min.	40
Diameter of tubing, in.	2.5
Power required, hp.	9.5

Another Louisiana well in the Caddo field gave test results as follows:

Depth, ft.	1000
Length of stroke, in.	37.5
Strokes per min.	38
Diameter of tubing, in.	3
Power required, hp.	17.5

The following formula is suggested for computing the power required for pulling tubing rods, and is based on the assumption of a mechanical efficiency for the rig of 50 per cent:

$$\text{hp.} = \frac{W \times d \times N}{63{,}000 \times L}$$

in which W = weight lifted in pounds.

d = diameter of bull-wheel shaft in inches.

N = rev. per min. of bull-wheel.

L = number of lines used in the tackle.

Swabbing a well sometimes results in a peak load as great as 70 kilowatts. The total monthly power consumption for a producing well, including pumping, pulling rods, etc., ranges between 1350 and 6000 kilowatt-hours, with an average of about 2100.

Slip-ring induction motors are nearly always used for a producing well. These are of the Y-delta or the two-speed type. In some cases one motor is used for pumping a well, and a separate portable motor and outfit serves for pulling tubing and cleaning several wells. While this allows each motor to be designed especially for the particular work it is to do, most operators find it more convenient to use a single stationary motor for all purposes. Where a separate portable motor is used it may be coupled to a hoist mounted on a truck, or the motor alone may be portable and designed to be belted to the countershaft at each well.

Motors are also used in connection with pumping jacks. This system requires 2.5 hp. per well per day on an average, a considerable saving over individual operation. Jacks are, however, seldom used except when the production per well is comparatively low, since it is impossible to pump each well at the most advantageous speed.

KERN TRADING & OIL COMPANY—1914
ELECTRIC POWER FOR PUMPING OIL WELLS—SECTION 15-A SUNSET

	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Monthly average for 1914
Total K.W.H.	38576	34960	35008	32752	33920	31552	32768	32544	33040	30688	31312	36736	33654
K.W.H. per well hour	4.99	5.02	4.85	5.036	4.596	4.470	4.235	4.194	4.428	3.940	4.148	4.703	4.551
K.W.H. per well per 24 hours	119.71	120.41	116.49	120.85	110.31	107.29	101.65	100.66	106.26	94.58	99.55	112.86	109.21
K.W.H. per bbl. of oil	1.783	1.830	1.719	1.695	1.973	2.01	1.96	1.88	1.87	1.67	1.88	2.49	1.90
Daily production per well	63.44	62.02	59.692	58.56	50.41	47.64	48.91	50.61	53.43	53.76	50.35	43.31	53.51
Total bbls of oil for month of	21635	19101	20355	19325	17193	15721	16681	17268	17635	18332	16617	14768	16275
Hours run per day per well	22.68	22.62	21.15	19.70	21.642	21.388	22.689	22.75	22.61	22.83	22.87	22.91	22.15
Line pressure	109.19	112.96	88.06	73.83	59.85	49.66	50.80	49.51	50.00	56.30	63.83	595.16	71.55
Cost per well day of 24 hours	$1.197	1.204	1.165	1.208	1.103	1.073	1.0164	1.0066	1.0626	.9458	.9954	1.1286	$1.0839
Cost per bbls of oil	$0.0178	.0183	.0172	0.0169	0.197	.0201	.0196	.0188	.0178	.0167	.0188	.0248	$0.0188
Actual cost per well day	1.1317	1.1355	1.0258	0.9093	.9947	.9560	.9609	.9514	1.0011	.8999	.9488	1.0773	$0.9994
Power off, hours	7	2	0	1/12	0	2	0	2	9	2½	1	0	2.7

NOTE.—Well No. 16 not included. Average gravity of oil 15.4 degrees. Average depth of wells 912 feet. All wells operate tail pumps at line pressure given. Cost of power figured at 1 cent per K. W. H. Number of wells, 11.

KERN TRADING & OIL COMPANY—1915
ELECTRIC POWER FOR PUMPING OIL WELLS—SECTION 15-A SUNSET

	Jan.	Feb.	Mar.	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Monthly average for 1915
Total K.W.H.	37,568	32,704	36,880	19,840	24,688	24,016	24,624	23,904	24,688	26,624	30,560	35,952	28,504
K.W.H. per well hour	4.5960	4.4580	4.3104	4.5111	4.1312	3.7062	3.6774	3.5763	3.8098	3.9832	4.7594	4.5816	4.175
K.W.H. per well per 24 hours	110.3040	106.9920	103.4496	108.2673	99.1488	88.9488	88.2576	85.8312	91.4352	95.5968	114.2256	109.9584	99.9512
K.W.H. per bbl. of oil	2.5473	2.7452	1.7729	1.0322	1.5105	1.5228	1.5770	1.6103	1.8860	1.9148	2.2423	2.3141	1.8896
Daily production per well	39.645	35.460	57.54	53.35	43.935	43.806	41.975	39.903	36.36	37.37	37.86	41.76	42.413
Total bbls of oil for month of	14,748	11,913	21,406	19,221	16,344	15,770	15,615	14,844	13,090	13,903	13,629	15,536	15,506
Hours run per day per well	21.97	21.83	23.00	12.22	16.07	18.00	18.00	17.96	18.00	17.97	17.83	21.09	18.66
Line pressure	109.19	99.64	95.80	68.30	69.00	54.00	50.00	44.70	47.66	50.00	60.00	78.6	68.90
Cost per well day of 24 hours	$1.1030	$1.0699	$1.0345	$1.0826	$0.9915	$0.8895	$0.8825	$0.8583	$0.9143	$0.9559	$1.1422	$1.0995	$1.0019
Cost per bbl of oil	$0.0254	$0.0274	$0.0172	$0.0103	$0.0151	$0.0152	$0.0157	$0.0161	$0.0188	$0.0191	$0.0224	$0.0213	$0.01866
Actual cost per well day	$1.0099	$0.9733	$0.9911	$0.5511	$0.6634	$0.6669	$0.6619	$0.6426	$0.6857	$0.7157	$0.8489	$0.9664	$0.7814
Power off hours	0	0	0	40	0	0	0	0	0	0	0	0	3.33

NOTE.—Average gravity of oil 15.4 degrees. Average depth of wells 912 feet. All wells operate tail pumps at line pressure given. Cost of power figured at 1 cent per K.W.H. No of wells, 12.

Cost of Generating Electric Power With Diesel Engines—1916

A report presented at the convention of the National Electric Light Association contains some interesting data regarding Diesel-engine plants. The cost of Diesel-engine plants, complete, with generators and all auxiliary equipment, will ordinarily range from a little over $100 per kilowatt capacity in large plants to $150 in small plants. Two plants in Texas, one of about 1000 and the other of 600 kilowatts capacity, cost, exclusive of the power-plant buildings, about $128 each per kilowatt capacity. Including buildings the cost would be between $140 and $150 per kilowatt. The fuel consumption in a plant of moderate size, is about 0.1 gallon per kilowatt-hour.

CHAPTER VI

PIPE LINES

CONSTRUCTION AND OPERATION

GAS PIPE LINES[1]

During the early development of the natural gas industry, the ioneers in the business made many experiments with different tyles of pipe and joints. Many tests were made on the different oints, gates and various fittings.

The first line laid was a small wooden line, which was laid rom the Newton well to Titusville, Pennsylvania, in 1872. Small crew lines were next used, and were followed by leaded joint line, vhich later developed into the rubber gaskct joint of the present lay.

Plain end or rubber joint lines.—A coupling for plain end ipe consists of a center ring, two followers and two ubber gaskets. (See Fig. 139.) When laying a coupling ine, skids are placed across the ditch and the pipe is either arried or rolled on the skids (according to size and weight). One follower, one gasket and the center ring are placed on the irst joint, and the other follower and gasket are put on the next oint, which is fitted into the center ring on the first joint. Bolts re then placed through the followers and they are drawn up gainst the center ring forcing the gaskets against the center ring nd pipe, making a tight joint very similar to a stuffing box. (See Fig. No. 140). After a section of line has been laid, it is lifted off the skids by means of short scaffolds or horses and lowered nto the ditch as the skids are removed. Great care must be exercised in lowering coupling lines, or the joints will be strained and eaks develop.

[1]By C. E. Brock, (Trans. Am. Soc. Mech. Engrs.)

A great many different styles of couplings have been used, starting with cast iron couplings, which make excellent joints, but are too heavy and easily cracked, if strained when the pipe is lowered into the ditch. Practically all couplings used today are made of steel and are built on one of two designs, viz., outside followers, which fit over the center ring, and inside followers, which fit under the center ring. (See Fig. No. 141).

It is the writer's belief that the outside follower coupling is the most practical for the reason that it is impossible for the rubber

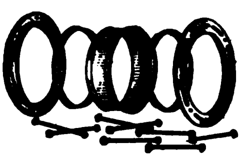


Fig. 139.—Plain end pipe coupling

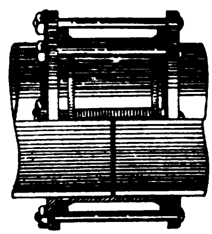


Fig. 140.—Longitudinal section plain end pipe coupling

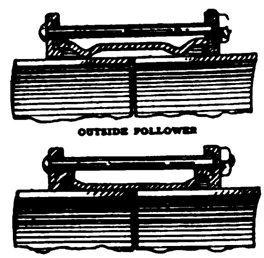


Fig. 141.—Inside follower

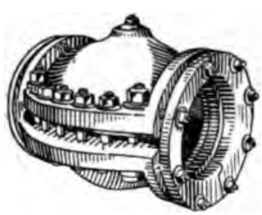


Fig. 142.—Emergency sleeve

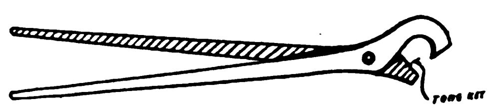


Fig. 143.—Tongs

to blow out between the follower and the center ring, while with an inside follower, a part of the rubber is pushed over the follower, and there is nothing to prevent the rubber from blowing out between the follower and the center ring, in which case the gas flow cannot be shut off temporarily with wooden wedges while repairs are being made.

Repairing coupling lines.—Leaks on coupling lines occur from three different causes, viz., rubber blowing out, cracked center ring or broken follower, and in case the leak is of any consequence, it can be repaired without interrupting the service, by installing an emergency sleeve over the coupling.

This sleeve is made in six pieces—two large halves and four

half followers, which, when jointed together, make a joint similar to a coupling. The large halves also have inside rubbers, which make them gas-tight, and a relief valve is located in the top half, through which the gas flows while the repair is being made, and when completed the valve is closed, making a tight joint. (Fig. No. 142). The sleeves are left on until it is convenient to shut the line out to remove them, and repair or replace the coupling.

With the development of natural gas in the Mid-Continent field, it was found that the rubbers heretofore used in coupling lines were affected by the gasoline in the gas, and after a short time were eaten out. About six years ago gasoline-proof rubbers were put on the market, and practically all lines laid with these rubbers have given very little trouble. These rubbers have a tendency to enlarge when saturated with gasoline, and in this way make a very tight joint. On a pipe line system in California, it was found after a gasoline plant was installed that leaks occurred along the line due to shrinkage caused by the rubbers drying out, and it became necessary to by-pass the gasoline plant occasionally and allow the rubbers to become saturated with gasoline until they were swelled sufficiently to shut off the leakage.

The great advantage in laying a coupling line is the speed at which it can be laid. There is practically no limit to the amount of any size of plain end pipe which can be laid in one day except the number of men employed on the work. While screw pipe will carry higher pressures than plain end pipe, the following table of tests will demonstrate the ability of plain end lines to carry high pressure with a margin of safety.

Size, inches........	6	8	10	12	16	18
Weight, lbs	17	24	32	42	48	53
Pressure	450	400	400	350	325	300

Welded lines.—In the natural gas business, a large amount of screw pipe and casing becomes useless after being used once or twice unless it is re-threaded and new collars put on. To eliminate this expense by using casing unfit for further use in drilling, experiments in laying welded pipe lines were started in 1916.

Several small lines were laid in the Mid-Continent field, and gas men were so well pleased with the results that attempts at welding large lines were made. A 10-inch line was laid by the Wichita

Pipe Line Company from Drumright to Cushing, on which very few leaks have occurred since the completion of the line. The Oklahoma Natural Gas Company laid a 10-inch line from Dilworth to Enid with good results, allowance being made for expansion and contraction by digging a wide ditch and blocking the line first on one side of the ditch, then on the other. Later the blocks were burned, leaving sufficient slack in the line to care for all the expansion or contraction

In 1917 the Wichita Natural Gas Company laid a 12-inch line from the El Dorado field to Valley Center, Kansas, but this line did not give as good results as the 10-inch line mentioned. A great many breaks occurred, and in places this line would pull apart three or four inches.

Another 12-inch line laid by the Empire Gas and Pipe Line Company from Bigheart to Hominy, Oklahoma, also gave considerable trouble, breaking as often as sixteen times in twenty-four hours.

All of the above mentioned lines were laid without expansion sleeves or couplings, and after watching closely the operation of these lines, it is the opinion of the writer that it is impracticable to lay welded lines larger than 10-inch without allowing for expansion and contraction.

The process of laying welded lines must necessarily be slow on account of the time required to make a weld and the scarcity of good welders. The field is full of welders, who are graduates of welding schools, where they are taught to weld castings and flat steel; but these men must be taught how to weld pipe after they reach the job.

Large lines are usually welded in sections of six or eight joints before lowering into the ditch, and bell holes dug to weld the line solid. This process saves much time and digging, and gives the welder a chance to roll the pipe when welding, rather than lay on his back in the ditch to weld the bottom of the joint.

The two principal welding irons used are vanadium steel and Norway iron, both of which are good; but better results are obtained with the Norway iron on account of it being a softer metal.

The greatest drawback to welded lines is the great inconvenience and danger in repairing a break. It is almost impossible

to repair a cracked weld with high pressure in the line for two reasons: First, if the crack is very large, the gas pressure will be too great to permit the use of an emergency sleeve. Second, if the top half of the sleeve is accidentally dropped on the pipe, the weld is likely to give way entirely, allowing a large volume of gas to escape, and blow the top half of the sleeve and the men out of the ditch. In order to avoid such danger, the writer found it advisable to instruct all field men to always shut out and drain a welded line before attempting repairs, which of course would be disastrous to the service if the line were the only source of supply to the market.

The writer does not recommend welded lines in sizes larger than 8-inch without using a coupling, or expansion sleeve, every six or eight joints; but lines smaller than 8-inch can be laid successfully and in connection work, such as wyes, tees, ells, etc., welded work can be depended upon, and if properly done, a great saving is effected.

Excellent work has been done with the welding process in building meter stations, regulator stations, gasoline plants and refineries, in the construction of which it is necessary to do a large amount of pipe fitting, which, when constructed with threaded nipples and flanges, is slow and expensive.

In pipe line work, it is more practical to use acetylene and oxygen in tanks, on account of the necessity of moving often; but in stationary work, an acetylene generator can be used, and the acetylene generated at about half the cost of the same in tanks.

The following table of tests on strength of welds, made by the Kansas City Testing Laboratory, shows the relative strength of the weld to the pipe:

WELDING ROD TESTS

Description	Elastic limit per sq. in.	Ultimate strength per sq. in.	Elongation % in 8 inches	Reduction area %	% of elastic limit of welded sample to unwelded sample	% of ultimate strength of welded sample to unwelded
Vanadium No. 1	46250	56870	11	75		
Vanadium No. 2	75360	79600	10	75		
Norway No. 1	42600	50300	35	60		
Norway No. 2	63620	59200	20	75		

PIPE AND WELD TESTS

Description	Elastic limit per sq. in.	Ultimate strength per sq. in.	Elongation % in 8 inches	Reduction area %	% of elastic limit of welded sample to unwelded sample	% of ultimate strength of welded sample to unwelded
Pipe Sample No. 1	48000	56360	22	40		
Welded Sample No. 1	46350	54660	8	21	96	97
Welded Sample No. 2	38800	38800	0	0	81	69
Welded Sample No. 3	37600	41000	3	12	88.3	72.6
Welded Sample No. 4	31940	31940	0	0	67	54.5
Pipe Sample No. 2	42280	60080	22	40		
Welded Sample No. 1	39400	44620	3	16	93.5	74.3
Welded Sample No. 2	38680	42800	3	12	91.5	71.4
Welded Sample No. 3	38080	51190	5	18	90.1	85.3
Welded Sample No. 4	33950	47750	6	11	80.2	74.1

In these tests, four different brands of welded samples and two different brands of pipe were used.

Screw lines[1].—Screw lines are laid by two different methods, viz., by hand and machine. In laying pipe by hand, one of the gang, designated as a "stabber," starts the joint of pipe into the collar of the preceding joint and rolls it by hand for several threads to see that it is not cross-threaded. The joint is then screwed up as far as possible with a snubbing rope, and tongs are used to tighten it. These tongs are equipped with a square key, which is the only gripping surface on the tongs, and this key can very easily be turned or replaced. Before laying screw pipe, the threads should be oiled with a heavy oil or pipe dope, which will aid in screwing up the joint, and will also preserve the threads and make the joints easy to break when reclaiming a line.

Screw connection work, where only flange unions are used, is a very particular job, requiring great patience and accuracy; but when completed, makes the best connection. However, a large amount of screw connection work is finally connected with a solid steel sleeve, similar to a plain end coupling, but of greater length, to allow for expansion or contraction.

Several machines are manufactured with which it is possible to lay screw lines by power. This method is much faster than laying with tongs, but requires careful supervision to avoid screwing up a joint cross-threaded, or burning the threads by running up a joint too fast.

Two principal pipe machines used in the Mid-Continent field are the Buckeye and Mahoney, or California pipe machine.

[1]Editorial Note.—This data applies equally well for oil pipe lines.

The Buckeye machine moves on caterpillars and the pipe is laid from the back end of the machine.

The Mahoney machine is not equipped with caterpillars, but moves on the pipe by means of a traveling gear, which is operated by a clutch. When a joint has been laid, a jack is placed under the head end of the joint, and the machine moves ahead to the end of the joint by means of this traveling gear. The machine is also equipped with a jack on which it is raised by power to take the weight off the pipe while another joint is being screwed up. Two sets of tongs are located on the front end—one for backups to hold the joint previously laid, and another to tighten the next joint. When it is desired to make an over-bend in the pipe, it is merely necessary to place a jack under the pipe at the point where the bend is to be made, and run the machine ahead far enough to give the desired weight to make the bend. An attachment may also be purchased for these machines with which it is possible to make a sag bend in the pipe. This is done by the use of a 10-ton hydraulic jack, operated by power from the motor. A force of fifteen or twenty men can operate the Mahoney machine, and where the country is fairly level, a great deal of time can be saved, as it is possible to lay from thirty to forty joints an hour.

Screw pipe, while used in laying small gas lines, is used entirely in laying oil lines, as a much higher pressure can be maintained on a screw line than on a coupling or plan end line, and after a time rubbers in coupling line will become affected by the oil. There is also considerably less friction in a screw line than in a coupling line, due to the different design of the joints.

General.—In laying gas pipe lines, there are many details, which aid efficient and continuous operation of a line.

When connecting wells in a field, it is always good policy to install a check valve in the line, from the well to the main line, at the point where the well line connects to the main line, to avoid loss of gas in case of a break in the well line or gate or tubing in the well.

In the fields where salt water or gasoline is encountered with the gas, it is necessary to install traps or drips to catch the fluid before it reaches the main line, as fluid affects measurement of the gas, regulation of pressure, operation or compression stations, and at times even reaches the consumer's meter. A great many different styles of drips have been designed to catch this fluid, and all

perform in practically the same manner—that is, they allow the gas to expand and decrease the velocity, which causes precipitation of the entrained fluid.

When constructing a main pipe line, it is advisable to install a main line gate every four or five miles, with a relief valve and pressure gauge tap on each side of the main line gate. When a line is so laid, it is possible, in case of a break to shut out a short section of the line, and exhaust the gas through the relief valves, without draining the entire line and discontinuing service to consumers on sections of the line not affected by the break. With the gauge taps, it is possible for the man supervising the repair to observe the pressure being maintained on either side of the break.

In constructing river crossings for pipe lines which must give continuous service, it is always advisable to lay more than one crossing. The lines in the river can be of smaller pipe than the main line, but the total capacity should equal that of the main line. River crossings should be laid in deep water when possible, as the greater depth will lessen the danger of having the line torn out by drift. A line should never be laid straight across a stream, but swung in an arc upstream, the radius of the arc varying with the length of the crossing. In this manner, the resistance of the line is greatly increased and many breaks avoided.

River lines are usually laid of screw pipe and each collar covered with a river clamp which removes all strain from the joint and adds weight to the line.

Occasionally welded river crossings are constructed,and in this case a split emergency sleeve or a river clamp, which has a rubber packing similar to that of an emergency sleeve, should be used, as it would be impossible to repair a welded crossing without first removing from the water or constructing cofferdams.

In operating a gas pipe line system, it is practical to carry the lowest pressure with which it is possible to handle the market, and in cases where small towns are located some distance from the main line and are supplied by smaller lines, regulators are installed at the main line and the pressure reduced, rather than carry main line pressure to the town limits.

In the operation of a natural gas system, it is impossible to turn in all gas available and allow it to go where it will, as the consumers on one part of the system would have an over supply of fuel, while the consumers on an other part would suffer from

shortage. To avoid such unequal service, gas companies maintain what is usually known as a dispatcher's office. This department receives pressure reports by telephone from all important points on the system at certain intervals during the day, and by carefully tabulating and observing these pressures, they are able by regulation of the gas to maintain sufficient pressures throughout the entire system. In case of line breaks or line shut outs for any reason, the field men are required to notify the dispatcher's office before a line is taken out of service, in order that the service may be maintained by supplying from another source. In fact, the duties of a pressure dispatcher parallel those of a train dispatcher, and all wells, lines and regulators are operated upon orders from him.

In the operation of a pipe line system, the entire effort of the organization is devoted to giving continuous service, and in order to do this, men are stationed at various places along the system. The lines are patrolled continuously by line walkers, who repair small leaks as they find them, and report to their immediate superior, leaks which they cannot repair. In such cases, a crew is taken to the leak at the earliest possible moment to make the re-vairs.

PIPE LINE IN MEXICO TO HANDLE 12° BAUME MEXICAN OIL.

In 1913 the East Coast Oil Co., S. A., began the construction of an 8-inch pipe line from the Panuco field in Mexico to their Torres terminal located on the Panuco River just above Tampico. The total distance was only 23.8 miles but the product to be handled was of 12 degrees Be. gravity which made it necessary that special methods be employed.

After careful consideration it was decided to construct the line along the following plan:

1. To pump at high heat in order to keep the viscosity of the oil as low as possible.

2. To pump at high pressure in order to get the necessary volume.

3. To put the pump stations fairly close together.

4. To provide necessary facilities so that the line would never be shut down or cool off when it was full of the 12 degree Be. oil.

The actual construction of the line was about the same procedure as the laying of an 8-inch line in the United States. In

order to conserve the heat as much as possible the pipe line after being coated with hot asphalt was covered with 1 ply Ajax insulating felt. No expansion joints were provided along the entire length of the line. A complete list of tools used and force employed is given herewith:

Tools and Material Necessary for Laying 8-Inch Pipe In Mexico. Average 2800 Feet Daily.

5 pair Klein 8-inch tongs.
60 keys for same.
10 wedges for keys.
1 two-ton Chain Block.
1 derrick for same.
2 jacks for 8-inch pipe
2 jack boards.
2 sharp pointed bars.
3 machinists No. 2 hammer and handles.
1 three-inch flat paint brush for greasing collars.
100 feet 1-inch Manilla rope, cut in about 25-foot lengths
2 pieces O. P. Rough Select 2x12-inch x 8 feet.
125 pieces O. P. 4x6-inch x 7 feet for skids
1 Acme water barrel cart.
1 fifty-gallon water barrel.
3 cups for same.
10 pounds flake graphite for mixing with crude oil used on collars and threads.
2 round nose shovels—long handle.
2 thread cleaning brushes.
2 large bastard files.
1 monkey wrench for removing protectors from pipe.
1 swab with 22 feet ½-inch pipe on to run through joints
2 eight-inch C. I. screw plugs.
1 eight-inch wooden plug, tapering shape, for use in snaking pipe.
1 chain on same.
1 pair lead bars for snaking pipe
2 horses for snaking pipe.
1 pair pipe carrying calipers.
1 pipe carrying bar.

Tools and Material Necessary for Placing Protection on 8-Inch Pipe Line—Asphaltum Paint

Kettles for heating.
Cover for kettles.
Heating frames.

Dippers for filling buckets, about $2\frac{1}{2}$ gallons.
Buckets—14 quarts (9 for one gang).
Wire cutter (large tinsman shears).
Paint brushes (9 for one gang).
Frame for measuring and cutting wire
Double bitted axes.
Sled for hauling kettles.
Low flat wagon for hauling paint and paper
Frame horse for cutting paper.
Metallic tape line for measuring paper and pipe.
Book for measuring paper.
Small derrick with 2-ton chain blocks and grab hooks.

Crew Necessary for Laying 8-Inch Line (Average Amount) Laid 2800 Feet Daily

1 Stabber.
1 Hammer man.
1 Rope man
1 Back up tong man.
1 Thread greaser.
1 Growler board man.
2 Bar men.
2 Jack men.
2 Jack board men.
2 Derrick men.
24 Tong men.
Snaking pipe, 1 teamster.
Cleaning threads, 1 man.
Removing protectors, 1 man.
Swabbing pipe, 1 man.

Cleaning Pipe

4 Brush and sack men.

Papering and Covering

1 Paint foreman.
1 Kettleman—heating kettles.
1 Teamster hauling and moving kettles.
1 Swamper or teamster.
1 Kettle dipper man.
4 Paint carriers.
5 Painters painting pipe.
1 Painter painting seams on paper.
3 Painters painting collars.
3 Paper men placing long paper.
3 Collar men placing paper on collars.

2 men cutting and measuring paper.
1 Man wiring paper.
Total, 27 men.

This paper crew will have ample time to clean out trench or ditch after covering and painting.

Pumping Stations and Equipment

The approximate distance between the pumping stations is as follows:

Panuco Field Station to Station "A"	1.2 miles
Station "A" to Station "B"	11.4 miles
Station "B" to Torres Terminal	11 miles
Total	23.6 miles

The stations "A" and "B" mentioned here are equipped with 15x24x6x24 Jeansville compound steam pumps, 60-inch oil heaters and the necessary boiler capacity for heating the oil and operating the pumps. From the storage tanks to the pumps 16-inch suction lines are used, and heating coils are used in the tanks. A complete list of tools used in equipping each of the stations follows:

List of Pump Station Tools

1 No. 1 Saunders Cutter, 1/8 to 1 inch pipe.
1 No. 2 Saunders Cutter, 1 to 2 inch pipe.
1 No. 3 Saunders Cutter, 2 to 3 inch pipe.
1 No. 4 Saunders Cutter, 2½ to 4 inch pipe.
1 No. 5 Barnes Cutter, 4 to 5 inch pipe.
1 No. 6 Barnes or special cutter for 8-inch pipe.
6 Spare cutter wheels for each.
1 No. 1 Bridgeport Stock and Die, 1/8 to ½ inch pipe.
1 No. 2 Bridgeport Stock and Die, ¼ to 1 inch pipe.
1 No. 1 Toledo Stock and Die, 1 up to 2 inch pipe.
1 No. 2 Toledo Stock and Die, 2½ to 8 inch pipe.
1 No. 3 Toledo Stock and Die, 4½ to 8 inch pipe.
1 No. 1 Crane Mal. Pipe Vise, 1/8 to 2 inch pipe.
1 No. 2 Toledo Pipe Vise, 3 inch pipe.
1 No. 4 Holland Pipe Vise, 4 inch pipe.
1 Pipe Vise to take 8-inch pipe.
1 100 pound Anvil.
1 Pipe Tap of each size, 1/8, ¼, 3/8, ½, ¾, 1, 1¼, 1½, 2 inches.
1 No. 7 Little Giant Stock and Dies, ¼ to 1 inch.

1 No. 30 Little Giant Stock and Dies, 1⅛, 1¼, 1⅜, 1½ inches.
All to be United States Standard Threads and exact size.
2 Each single-ended engineers' wrenches, diamond "W" pattern, rough handles. Milled Jaws to fit ⅜, ½, ⅝, ¾, ⅞, 1, 1⅛, 1¼ inches, United States standard thread hexagon nuts.
1 No. 53 Combination 200 Keystone Ratchet Drill.
1 No. 3 to No. 2 Taped Slave.
1 No. 3 to No. 1 Taped Slave.
2 Each, Twist Drills, ¼ to ¾ inches, inclusive, increasing by 1/32 inch.
1 Each, Twist Drills, 13/16 to 1¼ inches, inclusive, increasing by 1/16 inch.
1 6-inch Trimo Pipe Wrench.
1 8-inch Trimo Pipe Wrench.
2 10-inch Trimo Pipe Wrench.
2 14-inch Trimo Pipe Wrench.
2 18-inch Trimo Pipe Wrench.
2 24-inch Trimo Pipe Wrench.
1 36-inch Trimo Pipe Wrench.
1 Combination and Machinist Pipe Vise to take up 4-inch pipe (Parket).
1 Blacksmith Forge.
2 1¼-inch No. 51 Cold Chisel.
2 1¼-inch No. 52 Hot Chisel.
2 1x2½-inch No. 53 Hardie.
2 ⅝-inch No. 55 Top Swedges.
2 ⅝-inch No. 56 Bottom Swedges.
2 ½-inch No. 57 Bottom Swedges.
2 ½-inch No. 58 Top Swedges.
2 2-inch No. 59 Flatters.
5 pounds No. 48 "Seine" Hard Laid Chalkline.
1 10-pound Sledge, 2 handles for same.
1 16-pound Nevada Sledge, 2 handles for same.
1 Pair P-24 Tongs.
1 Pair B-14 Tongs.
1 Pair H-10 Tongs.
1 Pair V-6 Tongs.
2 No. 12 Vulcan Chain Pipe Tongs. (Flat chain.)
2 No. 13 Vulcan Chain Pipe Tongs. (Flat chain.)
2 No. 13½ Vulcan Chain Pipe Tongs. (Flat chain.)
2 No 14 Vulcan Chain Pipe Tongs. (Flat chain.)
1 No. 15 Vulcan Chain Pipe Tongs. (Flat chain.)
2 Large Klein Tongs for 8-inch pipe.
1 Carpenter's outfit complete.
1 2-man Cross-cut Saw.
2 6-inch Monkey Wrenches.
2 8-inch Monkey Wrenches.
2 12-inch Monkey Wrenches.

2 15-inch Monkey Wrenches.
1 18-inch Monkey Wrench.
1 24-inch Monkey Wrench.
3 Machinists Hand Hammers as selected.
1 Good Spirit Level (Iron), selected.
2 ½-pound coils of piano wire.
6 ½-inch Machinists' Flat Chisels.
2 Half-round Chisels.
4 Diamond point Chisels.
2 Boilermakers' Riveting Hammers.
1 Blacksmith Hammer.
1 Blacksmith Hammer.
1 Carpenters' Saw.
1 Hand Ax.
1 Large Ax.
12 6x48-inch Hard-Wood Rollers.
1 1-ton Chain Hoist, duplex.
1 2-ton Chain Hoist, duplex.
2 Barrett Jacks.
2 Screw Jacks.
2 6-inch Double Blocks.
2 6-inch Treble Blocks.
2 8-inch Treble Blocks.
2 8-inch Double Blocks.
Coils of Rope as selected for Fauls, Slings, Lashings, etc.
6 16-inch Flat Bastard Files.
6 16-inch Flat Second-Cut Files.
6 10-inch Flat Second-Cut Files.
6 10-inch Half Round Second-Cut Files.
3 ⅝-inch Round Files.
3 ⅜-inch Round Files.
24 Sheets No. 0 Emery Cloth.
24 Sheets No. 00 Emery Cloth.
1 2-pound Can Carborundum.
1 Drum of Distillate.
1 Drum of Kerosene.
1 Drum of Cylinder Oil.
1 Drum of Engine Oil.
2 Bundles of rags. (100 pounds.)
2 Hack Saw Frames.
48 Hack Saw Blades.
1 Pair of Hand Pliers.
6 Hand Shovels.
6 Picks
6 Spare Handles for picks.
1 Wheel Barrow.

1 Hand Truck.
Lumber for Carpenter and Vice Benches.
4 Rat-tail Files.
4 12-inch Flat Smooth Files.
1 Special Socket Wrench for nuts on 1¼-inch bolts, manifolds, etc.
1 Steel Bar for same.
8 Hand Lanterns.
1 Tube Expander and spare Rollers for Boilers.
1 Tube Expander and spare Rollers for Heaters.
2 Beading Tools for Boiler Work.
2 Ripping Tools for Boiler Work.
2 Fullering Tools for Boiler Work.
1 Go Devil for Boiler Tubes.
1 Pair of small blocks and rope as selected for light work.
1 Snatch Block.
2 Large Pinch Bars.
2 Small Pinch Bars.
2 Small Bars, pointed one end and flat other end, as selected for fairing flanges, etc.
Necessary Packing for all Machinery, Valves, etc.
Jointing for same.
Spare Bolts and Nuts from ½ to 1¼-inch, and various lengths.
Spare Pipe from ¼ to 6 inch, inclusive.
8-inch Spare Pipe.
Spare Fittings from ¼ to 6 inch, such as Valves, Ells, Tees, Flanges, etc.
Electrical Apparatus Spares.
Wire, Lamps, etc.
Pole Climbers, Plyers, etc.
1 Bar of 1-inch Tool Steel for Chisels, etc., can be hexagon or round.

The oil leaving the steel storage tanks moves through the 16-inch suction line to the 60-inch heater in which it is heated up to about 160 degrees Fahrenheit, either with live steam or with exhaust steam from the pumps. The line pressure when pumping at the rate of 19,000 barrels per day will average 800 pounds to the square inch at the pump. After traveling 11 miles at this velocity the oil cools down to around 120 degrees Fahrenheit, average temperature.

A duplicate set of pumps is provided in each of the pumping stations so that should anything happen to one set the other can immediately be put into the service. This is done to prevent the line cooling off when filled with the heavy oil.

If at any time the storage tanks become pumped out and it is

desired to shut the line down water is pumped in behind the oil and when the pumping ceases the line is left full of water. On resuming pumping water is again pumped through the line (first passing through the oil heater) until the line has been thoroughly heated and then the hot oil is started through. The small amount of mixed oil and water coming through is caught in a separate tank and the water drained off.

The line has been in continuous operation for periods as long as one year without having to shut down and fill with water.

At the Torres Terminal 16x10x18 Jeansville pumps are used for loading tank steamers. These pumps load the heavy oil on the tankers at the rate of 5000 barrels per hour.

A Mexican engineer, Senor Juan Mancera, has made a study of this line, and worked out several curves which will be of interest to anyone working on the problem of handling oil of this quality.

SUBMARINE PIPE LINES

Where it is desired to load oil into ocean-going tank steamers and there is no available harbor or where the cost of terminal facilities would be prohibitive, it is often necessary to lay a submarine line seaward to a point where the oil can be loaded directly into the tankers. This is notably the case in the southern fields of Mexico where there is no deep water harbor between Tampico and Vera Cruz and where the shore line is low and the water shallow for some distance out into the Gulf of Mexico.

These conditions, however, permit the laying of the line on shore and towing it to sea. The line is made up and mounted on rollers or on rail carriages. A ship's hawser is attached to the sea end of the line and towed out by launches to the tugs or larger steamers, one or more of which may be necessary. The sea end of the line should be plugged while towing out and should be mounted on a heavy wooden sled to prevent digging into the sand. A throat or guide, constructed of heavy timbers, should be provided on shore to guide the line until it enters the water as well as to counteract the off-shore currents.

The desired location for the end of the line is held by an anchored boat or lighter and the line is kept straight by a simple system of ranges on shore.

Especial attention should be given to making up the line. All connections should be carefully and thoroughly made and should be equipped with river clamps to protect them from breakage. The sea end of the line must be anchored. This can be taken care of with concrete blocks. The line terminates with a marine gate valve and stand pipe to which is attached a flexible metallic hose. Piling should be driven for the proper support and protection of the standpipe and it would also be advisable to drive nests of piles to prevent accident from the loading steamer.

Some sea loading lines terminate with a back pressure valve and a flexible metallic hose which rests on the sea floor when not in use, its location being marked by buoys.

Where the shore line will not permit laying the line as described it will be necessary to make up the line on barges and lower it as the work progresses.

An interesting description of the operation of towing a submarine line to sea for the Cia Transcontinental del Petroleo of Mexico, was recently printed in The Oil Weekly (9-4-20), and is described as follows:

Construction of submarine pipe line.—Preparations were started about a month before the lines were pulled in about the following order. A 36-inch gauge track was built and carefully aligned. A sharp drop was made at the beach end of track and a dolly pit dug out and covered with sheet steel, so that as the line was pulled out the dollies would drop off the track on to the sheet steel to be rolled away by men who were waiting for them. It was found that the distance between the beach and the Laguna which bounds the property on the west was only about 5000 feet, and as the length of the line to be pulled was 6500 feet, in order to get the 40 feet of water which was required, it became necessary to pull the line in two sections. As there are two lines to a berth, this necessitated the laying of two sections of line 5000 feet (the length of the track) and two additional sections of lines each 1500 feet to make lines 6500 feet in length when completed. Dollies or small trucks were made at the company's terminal at Tampico, consisting of four wheels under a wooden platform. The first 5000 feet section of line was thrown on the dollies, which were distributed along the line one to every other joint of pipe. A throat was built of heavy timbers on the beach and lined with sheet steel through which the line passed. This was to

prevent it from weaving north or south with the current when being pulled. A sand sled was built on the head of the line to prevent the pipe from burying itself while being pulled. A gasoline drum was tied on the top of the sled to keep the end of the line visible while being drawn out. A tower was built on the beach from which a simple signaling system was operated, controlling the starting, stopping and speed of the vessels pulling the line. Two beacons were put up along the line for guiding the vessels in taking their positions.

On November 18 everything was ready and the tanker H. L. Pratt arrived at 8 a. m. to pull the lines. The Aguila tug San Nicolo was used to guide the Pratt in the operation. The tanker came in as close to shore as possible and a mooring boat was sent out to bring in the towing hawser, a manila line 12 inches in circumference. On account of the strong current running, the hawser was not brought to shore until 1 p. m. At three o'clock the hawser was tied to the line and the ship started pulling. About 500 feet of line had gone out when a peon let a 2x4 inch timber drop on the track and caused six dollies to jump off. These were replaced by six new ones after a delay of 45 minutes and the pulling was resumed. The actual pulling time of the first section was about fifteen minutes. The second section of 1500 feet was then thrown on the track on dollies and connected up to the first section with a right and left hand thread coupling. By the time this work was finished it was six o'clock p. m., and everything was left in readiness for completing the work the next morning.

It was thought that after the first section had stood under water for twelve hours during the night it might get badly sanded up and some difficulty might be experienced in getting the line started again. Contrary to this opinion, the second section of the line was pulled the next morning in twelve minutes after getting started without any difficulty. By noon the men had finished letting water in the line, taking off the towing line, etc., and the Pratt went to Palo Blanco, where they pulled a line for the Metropolitan Company in half a day.

The same operation was repeated for the second line, which was pulled on the same track the next day. The first section of the second line was pulled in fifteen minutes; the second section of the line was thrown on the track and connected up in an hour's time

and the pulling of this section was completed in twelve minutes, making twenty-seven minutes actual pulling time for the complete line.

After the line is pulled and connected up to the pumps a flexible hose about 150 feet long is attached to the end of the pipe. This hose lies on the bottom of the Gulf when not in use. Its location is shown by buoys attached to the hose. When a ship comes in and is moored, the hose is pulled up and connected to the ship, and when the signal is given, by whistle, the shore pumps are started and oil is pumped through the line into the ship.

As a rule, the crude oil is pumped from the shore tanks at its natural temperature, but when greater speed in loading is desired the oil can be heated. Facilities are provided both for heating the crude before it starts on its 22 mile journey from the fields to the tanks on the beach and for raising its temperature in the tanks by means of coils through which exhaust steam is run. The sea water is warm and it rarely becomes necessary to increase the fluidity of the oil to enable the pumps to handle it.

This system of loading has proven the most satisfactory of any scheme in use anywhere in the world. The accompanying pictures make the process clear.

FRICTION PRESSURE LOSS IN OIL PIPE LINES[1]

Herewith is presented the recent development of the law governing the flow of liquids and gases in pipe lines, in a form and units convenient for the use of the practicing oil engineer.

Formulae.—The law developed is presented in the following formulae, the symbols used throughout being as indicated below.

(g) is the specific gravity or density of the oil.

(u) is the absolute viscosity in poises (dynes per sq. cm. per sec.).

(Q) is the quantity in U. S. gallons per minute.

(d) is the internal diameter of the pipe in inches

(R) is the value from Formula (1).

(c) is the coefficient for Formula (2) found from Chart A.

[1]Published by permission of the Kinney Manufacturing Company, Boston, Mass.

(P) is the friction pressure loss in lb. per sq. in. per 1000 ft of pipe.

$$R = \frac{g\ Q}{d\ u} \quad \text{Formula (1)}$$

$$P = \frac{c\ g\ Q^2}{d^5} \quad \text{Formula (2)}$$

Chart A (Fig. 147) shows the variations in the value of the coefficient (c) for various values of (R). To use the formulae the value of (r) is first determined from Formula (1). From Chart A the corresponding value of (c) for this value of (R) is then determined. This value of (c) is then substituted in Formula (2) and the pressure loss determined.

Formulae (1) and (2) cover all conditions of flow, but where the value of (R) is less than 65, the law may be expressed in the more convenient form of the following Formula (3):

$$P = \frac{27.3\ uQ}{d^4} \quad \text{Formula (3)}$$

Discussion of Chart A.—Chart A (Fig. 147) shows a curve with a sharp break. The portion (AB) indicates the so-called stream line flowing during which the oil flows in parallel lines through the pipe with no turbulence, the oil at the center of the pipe flowing at approximately twice the average velocity, and the velocity decreasing to practically zero at the outside layer. The portion (BC) indicates that flow changes suddenly from stream line to turbulent flow. The portion (CD) indicates turbulent flow during which the oil whirls and eddies in all directions.

Roughness.—The roughness of the pipe has no effect on the value of the coefficient (c) during stream line flow, but it has an effect during turbulent flow. This effect may be allowed for by elevating the portion of the curve (CD), the amount of this elevation depending upon the degree of roughness of the pipe. Under practical conditions in pumping oil, the roughness of the pipe used varies but slightly, and the position of the portion of the curve (CD) shown in Chart A is sufficiently accurate.

Critical velocity.—The critical velocity is the point at which stream line changes into turbulent flow. At this point a consider-

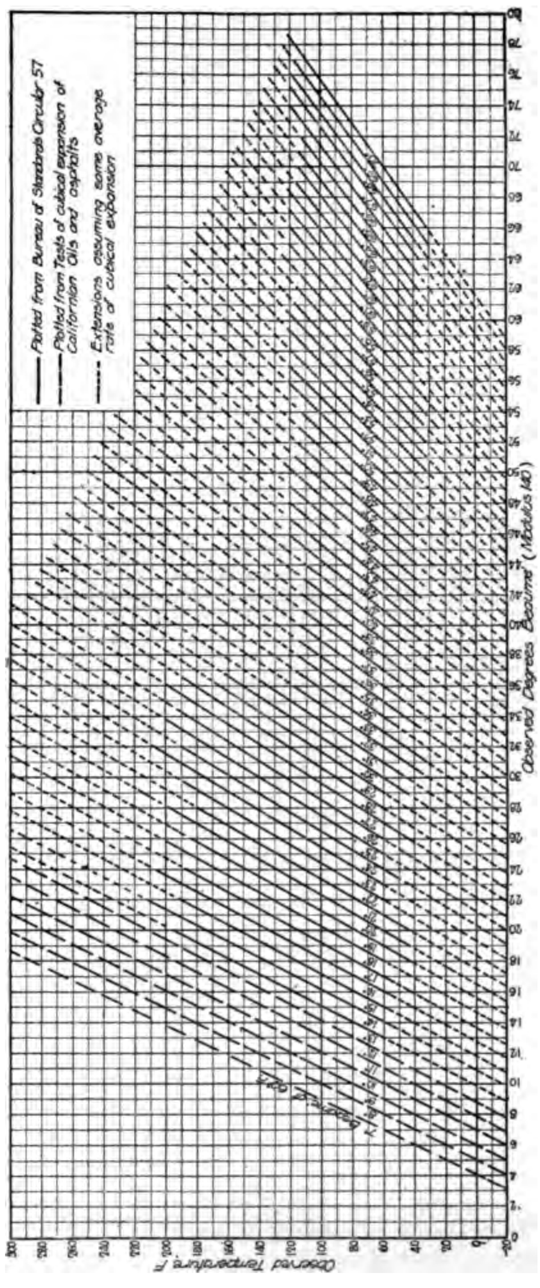


Fig. 145.—Chart C—Showing change in Baume gravity with variation of temperature.

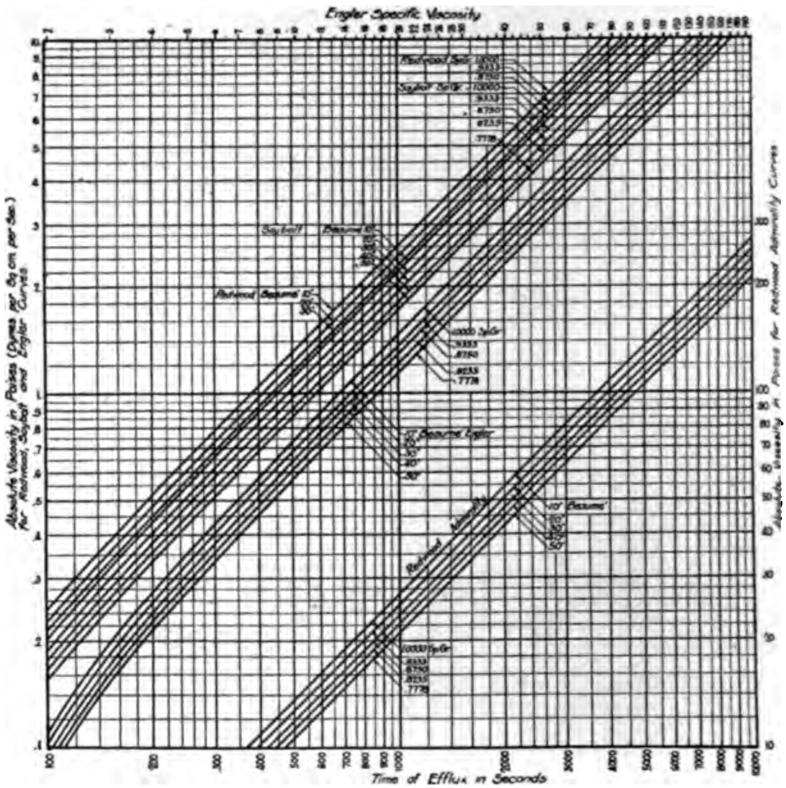


Fig. 146.—Viscosity conversion chart.

VISCOSITY CONVERSION CHART D

Formulae

Redwood $\frac{u}{g} = .00260t - \frac{1.715}{t}$ Saybolt Univ. $\frac{u}{g} = .00220t - \frac{1.80}{t}$

Engler $\frac{u}{g} = .00147t - \frac{3.74}{t}$ Red. Admir. $\frac{u}{g} = .027t - \frac{20}{t}$

u = Absolute viscosity in poises
g = Density or specific gravity
t = Time of efflux in seconds

For higher values than shown on chart divide the given time of efflux by 10 and multiply the corresponding absolute viscosity by 10.

For lower values than shown on the chart, use the formulae.

Gravity used must be the gravity at temperature of test.

able increase in pressure produces practically no increase in velocity. The value of (R) at which the critical velocity occurs depends somewhat upon the roughness of the pipe, also whether the velocity is increasing or decreasing. This is indicated by the portion of the curve (BC) where the value of (R) at the point (B) is shown at an average value of 65.

Specific gravity.—The specific gravity as used in the above formula should be the specific gravity (not Baume gravity) at the temperature at which the oil is flowing through the pipe line.

Chart B (Fig. 148) shows the change in specific gravity with variation of temperature. Chart C (Fig. 145) shows the change in Baume gravity with variation of temperature.

The table in the back of the book (Chapter VIII) shows the

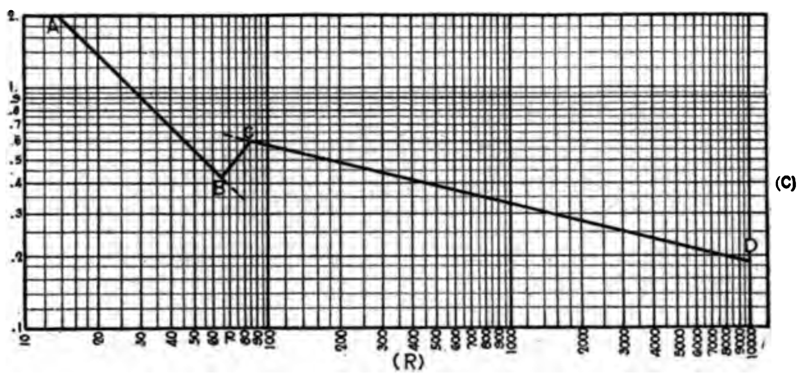


Fig. 147.—Chart A.

specific gravity corresponding to Baume gravity (Modulus 140) together with the lb. per sq. in. of pressure corresponding to one foot head of oil.

Viscosity Chart D.—The viscosity may be determined on any viscometer on which the determinations can be computed in units of absolute viscosity. Chart D (Fig. 146) shows the conversion of times of efflux of the Redwood, Saybolt Universal, Engler and Redwood Admiralty viscometers into absolute viscosity.

The conversion formulae given on the chart are taken from data in Technologic Papers Nos. 100 and 112 of the Bureau of Standards for the Redwood, Saybolt and Engler instruments, and from the papers by Messrs. Glazebrook, Higgins and Pannell (above mentioned) for the Redwood Admiralty instrument.

In determining viscosities at various temperatures it is of considerable assistance to plot the absolute viscosity against the temperature (in degrees F.) on logarithmic cross-section paper. In plotting these points it will be noted that all of these points lie on approximately a straight line, so that if the viscosity of a given oil at two or three temperatures is known, the viscosity can be readily determined for any other temperature. This, of course, applies to absolute viscosity only, and does not apply to times of efflux of the various commercial viscometers. In case of mixed or refined oils the location of these points is sometimes on a slight curve in place of a straight line.

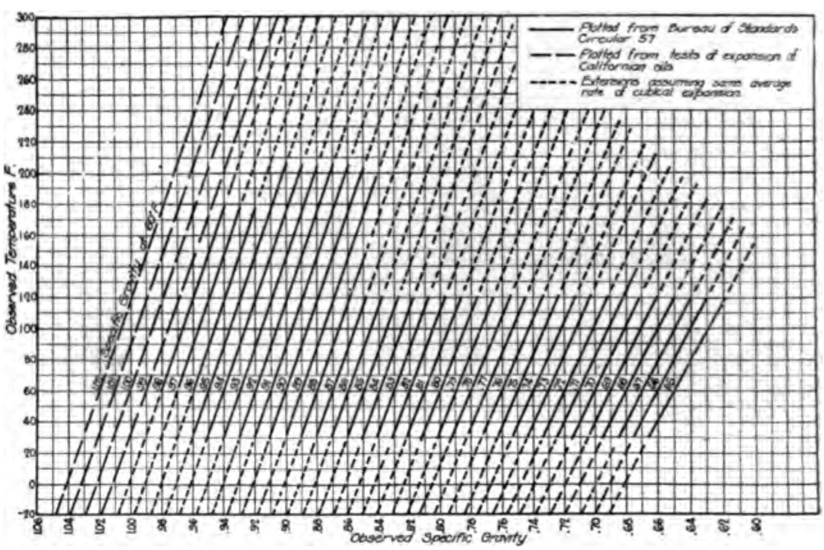


Fig. 148.—Change in specific gravity with variation of temperature.

Temperature.—The temperature of the oil during turbulent flow is uniform throughout the cross-section of the pipe. In stream line flow while pumping heated oils, the temperature is not uniform because the slowly moving outside layer of oil becomes considerably cooled with a consequent increasee in viscosity. The amount of this cooling has not yet been accurately determined, but from the data available under Californian conditions, the friction pressure loss for heated oils in stream line flow is increased from 10 to 50%.

In the usual practice of pumping heated oils, there is a drop

in temperature at a decreasing rate along the pipe line. An approximate rule recommended by the Standard Oil Company of California for the average temperature along the pipe line, is the sum of one-third the initial temperature plus two-thirds the final temperature.

Mexican oils.—A characteristic found in Mexican oils (and to a slight extent in California oils) is interesting in connection with this subject. This is a temporary lag in the viscosity due to a change in temperature. For example:

A sample of Mexican oil tested at 60° F. and stored for six days at 32° F. and again tested at 60° F. was found to have increased one-fifth in viscosity. Another sample heated to 150° F. for 49 hours was found to have only one-half the original viscosity when again tested at 60° F.

A third sample was stored at 32° F. for 120 days and at the end of this time the viscosity at 60° F. had risen to two and a quarter times the original value. This same sample was then heated at 100° F. for two hours and the viscosity at 60° F. found to have returned to its normal value.

In order to avoid loss of power and line capacity it is advisable, in handling Mexican oil which has been stored at low temperature, to heat the oil to at least 100° F. for at least two hours before pumping.

Other liquids.—The law as developed is applicable to the flow of any liquid or gas. Chart A covers all conditions of flow where the inside surface of the pipe is of the same smoothness as ordinarily used in oil work. On water pipe lines the roughness varies to a considerable extent and Chart A does not cover this condition.

Quantity in barrels.—If the desired capacity is given in (42 gallon) barrels per hour, the capacity may be changed into equivalent gallons per minute by multiplying the barrels per hour by 0.7. If the desired capacity is given in barrels per twenty-four hours, the capacity should be multiplied by 0.02917 to obtain gallons per minute.

Table II.—Gives the exact internal diameter of standard iron and steel pipe, together with the 4th and 5th powers of the diameter to facilitate solving formulae (2) and (3).

Friction pressure loss.—To determine the friction pressure loss

when quantity, size of pipe, specific gravity ,and absolute viscosity at the given temperature are known:

(a) Determine the friction pressure loss in pumping 500 gallons per minute of a given oil at 50° F. through a 6-inch diameter pipe, the oil having a specific gravity of 0.88 (29.1° Baume gravity) and an absolute viscosity of 0.3 at that temperature.

Substituting these values in Formula (1):

$$R = \frac{0.88 \times 500}{6.065 \times 0.3} = 242.$$

From Chart A for a value of (R) = 242. the corresponding value of (c) is 0.46. Substituting this value of (c) in Formula (2):

$$P = \frac{0.46 \times 0.88 \times (500)^2}{8206.} = 12.3 \text{ lb. per sq. in. per 1000 ft. of pipe line.}$$

(b) Determine the friction pressure loss in pumping 100 gallons per minute of a given oil at 60° F. through a 6-inch diameter pipe, the oil having a specific gravity of 0.9655 (15° Baume gravity), and an absolute viscosity of 35. Substituting these values in Formula (1):

$$R = \frac{0.9655 \times 100}{6.065} = 0.45$$

As the value of R is less than 65, use Formula (3):

$$P = \frac{27.3 \times 35 \times 100}{1353.} = 70.6 \text{ lb. per sq. in. per 1000 ft. of line.}$$

Gravity and viscosity.—To determine the gravity of an oil at the required temperature when the gravity at 60° F. is known, and the absolute viscosity at the required temperature when the viscosity at two other temperatures is known:

Determine the specific gravity and absolute viscosity at 45° F. of oil having a Saybolt viscosity of 250 seconds at 60° F., 102 seconds at 100° F. and 24° Baume gravity at 60° F.

From Chart C the gravity would be 26.5° Baume at 100° F., and 23.1° Beaume at 45° F. From the tables in Chapter VIII it will be seen that the corresponding specific gravity at 45° F. would be 0.914.

From Chart D (Fig. 146) the absolute viscosity at 60° F. correspondnig to 250 seconds Saybolt and 24° Baume gravity is 0.49 and the absolute viscosity at 100° F. corresponding to 102 seconds Saybolt and 26.50° Baume gravity is 0.185. Plotting these two absolute viscosities against the corresponding temperature on loga-

rithmic cross section paper, and extending a straight line through them, we determine the approximate absolute viscosity at 45° F. to be 0.85.

TABLE II

Diameter Functions of Standard Iron and Steel Pipe

Nominal Diam. inches	Wt. in Lbs. Per Lin. Ft.	Actual Diam. inches	d^4	d^5
½		.622	.14968	.09310
¾		.824	.46101	.37987
1		1.049	1.2109	1.2702
1½		1.610	6.7190	10.818
2		2.067	18.254	37.731
2½		2.469	37.161	91.750
3		3.068	88.597	271.82
4		4.026	262.72	1057.7
6		6.065	1353.1	8206.4
8	25.0	8.071	4243.3	34248.
8	28.8	7.981	4057.2	32381.
10	32.0	10.192	10790.	109980.
10	35.0	10.136	10555.	106990.
10	41.1	10.020	10080.	101000.
12	45.0	12.090	21365.	258300.
12	50.7	12.000	20736.	248830.
14		14.250	41234.	587590.
15		15.250	54085.	824800.

Friction Losses of Pennsylvania and California Oils[1]

When oil was discovered in Pennsylvania in large quantities, the problem of transportation was solved by laying pipe lines along the ground and pumping the oil from one station to another. For this service direct-acting pumps were adapted and exclusively used. The Pennsylvania oil, being light and of paraffine base, did not present any greater difficulties in pumping than water. The following formulas may be used for this work:

$$p = \frac{9\,B^2}{d^5} \qquad (1)$$

$$B = \sqrt{\frac{d^5\,p}{9}} \qquad (2)$$

where p equals friction in pounds per square inch for 10 English miles:

d equals diameter of pipe in inches;

B equals barrels per hour at 38 degrees Baume.

[1]Frank F. Nickel in "Direct Acting Steam Pumps," p. 210—McGraw Hill—by permission of publishers.

In formula (1), for every 3 degrees above 38 degrees Baume subtract 2 per cent from p and for every 3 degrees below 38 degrees Baume add 2 per cent to p.

In formula (2), for every 3 degrees above 38 degrees Baume add 1 per cent to B and for every 3 degrees below 38 degrees Baume subtract 1 per cent from B.

Greater difficulties were experienced with the Texas and California oils, which are of asphaltum base and very viscous. These oils offer an enormous resistance to being pumped through a pipe and will not move at all at low temperatures. It therefore becomes necessary in such cases to heat the oil with the exhaust steam from the pump.

In 1902 A. F. L. Bell made some tests in the Kern oil fields with heavy California oil. The pipe diameter was 8 inches and the following formula agrees well with the data obtained:

$$p = \frac{32768}{D^5} \times \frac{9}{t - 40} \sqrt[3]{B^4}$$

where d equals diameter of pipe in inches, for 1 mile;
p equals friction in pounds per square inch:
t equals temperature of oil in degrees Fahrenheit;
B equals barrels per hour.

The gravity was 14½° Baume at 60° F.

It is assumed that the friction varies inversely as the 5th power of d, no data being available for pipes of other diameters. The second term of the expression was developed on the assumption that at 40° F. the oil ceases to flow. The capacity then becomes zero.

Tables given in the following pages were calculated from the above formulas. It will be noted that while the table for Pennsylvania oil is calculated on a basis of 10 English miles and can be used for any length by simply multiplying the values given by one-tenth of the length, the table for California oil is given for one mile only. The reason for this is that the oil cannot retain its temperature for any length of time but has a different temperature at every point. This change of temperature is very difficult to predict and impossible to generalize, because it depends upon the manner in which the pipe is laid and the temperature of the outside air.

The two sets of tables may be taken as the limits, the former being correct for the very lightest oil and the latter for the very heaviest California oil. They should not be used, except as a guide, for oils of intermediate viscosities.

Friction of Pennsylvania Oil, 38° Baume

Pounds per square inch in pipe—10 English miles long

$d=$	2	3	4	5	6	8	10
$d^5=$	32	243	1,024	3,125	7,776	32,768	10,000
$d^{2.5}=$	5.66	15.6	32	55.9	88.2	181	316.2
Barrels per hour "B"							
10	28	3.7	0.88	0.288	0.116	0.0274	0.009
15	62	8.3	1.98	0.65	0.26	0.0641	0.023
20	112	14.8	3.52	1.15	0.462	0.11	0.036
25	176	23.0	5.5	1.8	0.725	0.172	0.056
30	253	33.2	7.92	2.6	1.04	0.247	0.081
35	345	45.2	10.8	3.53	1.42	0.337	0.112
40	450	59.0	14.3	4.6	1.85	0.44	0.144
45	570	74.9	17.8	5.8	2.35	0.556	0.181
50	700	92.4	22.0	7.2	2.9	0.686	0.225
55	850	112.0	20.6	8.7	3.5	0.84	0.273
60	1010	133.0	31.6	10.4	4.16	0.99	0.325
65	1184	156.0	37.2	12.2	4.9	1.16	0.381
70	1380	181.0	43.0	14.1	5.68	1.36	0.442
75	1580	208.0	49.5	16.2	6.51	1.55	0.508
80	1800	236.0	56.2	18.4	7.4	1.76	0.578
85	2030	267.0	63.5	20.8	8.36	1.98	0.652
90	2270	300.0	71.1	23.3	9.39	2.24	0.73
95	2530	334.0	79.2	26.0	10.45	2.48	0.814
100	2800	370.0	88.0	28.8	11.6	2.75	0.902
125	4400	578.0	137.0	45.0	18.1	4.3	1.42
150	6300	830.0	198.0	65.0	26.0	6.18	2.03
175		1130.0	270.0	88.0	35.4	8.4	2.75
200		1480.0	352.0	115.0	46.3	11.0	3.6
225		1870.0	425.0	146.0	58.5	13.9	4.55
250		2300.0	550.0	180.0	72.2	17.2	5.6
275		2800.0	665.0	217.0	87.5	20.8	6.8
300		3320.0	792.0	260.0	104.0	24.7	8.1
325		3900.0	930.0	304.0	122.0	29.0	9.5
350		4530.0	1020.0	353.0	142.0	33.7	11.2
375			1240.0	405.0	163.0	38.5	12.6
400			1410.0	460.0	185.0	44.0	14.4
425			1590.0	520.0	209.0	49.6	16.3
450			1780.0	582.0	235.0	55.6	18.3
475			1980.0	650.0	261.0	62.5	20.4
500			2200.0	720.0	289.0	68.8	22.5
525			2420.0	795.0	319.0	75.8	24.8
550			2660.0	870.0	350.0	83.0	27.3

Friction of Pennsylvania Oil, 38° Baume

Pounds per square inch in pipe—10 English miles long

$d=$	5	6	8	10
$d^5=$	3,125	7,776	32,768	10,000
$d^{2.5}=$	55.9	88.2	181	316.2
Barrels per hour "B"				
550	870	350	83	27.2
575	950	384	91	29.8
600	1040	417	99	32.4
625	1120	454	107	35.0
650	1220	490	116	38.0
675	1310	530	125	41.0
700	1410	569	135	44.2
725	1520	610	144	47.3
750	1620	653	155	50.6
775	1730	698	165	54.1
800	1840	743	176	57.6
825	1960	790	187	61.2
850	2080	839	198	65.0
875	2210	888	211	68.9
900	2330	940	223	73.0
925	2470	992	235	77.0
950	2600	1045	248	81.2
975	2740	1110	262	85.5
1000	2880	1158	275	90.0
1100	3480	1400	332	109.0
1200	4150	1665	395	130.0
1300	4860	1955	464	152.0
1400		2270	538	176.0
1500		2610	618	203.0
1600		2960	704	231.0
1700		3350	793	261.0
1800		3750	890	292.0
1900		4180	990	325.0
2000		4630	1100	361.0
2200			1330	436.0
2400			1580	520.0
2600			1860	610.0
2800			2160	706.0
3000			2475	811.0
3200			2840	922.0
3400			3180	1040.0
3600			3560	1170.0

$d=$	8	10
$d^5=$	32,768	10,000
$d^{2.5}=$	181	316.2
Barrels per hour "B"		
3600	3560	1160
3800	3970	1300
4000	4400	1440
4200		1580
4400		1740
4600		1920
4800		2070
5000		2250
5200		2430
5400		2620
5600		2820
5800		3030
6000		3240
6200		3460
6400		3680
6600		3920
6800		4160
7000		4410

Friction of Heavy California Oil In Four-Inch Pipe Line

Barrels per hour "B"	Temperature, Degree F=t 50	60	70	80	90	100
5	222	55.4	24.6	13.9	8.87	6.16
10	558	140.0	53.1	34.9	22.4	15.5
15	959	240.0	107.0	60.0	38.4	26.7
20	1,410	352.0	156.0	88.0	56.3	39.1
25	1,900	474.0	211.0	119.0	75.9	52.8
30	2,416	602.0	269.0	151.0	96.7	67.2
35	2,968	742.0	330.0	186.0	119.0	82.5
40	3,546	887.0	394.0	222.0	142.0	98.5
45	4,152	1,038.0	461.0	260.0	166.0	115.0
50	4,768	1,194.0	531.0	299.0	191.0	133.0
60	6,090	1,523.0	677.0	381.0	244.0	169.0
70	7,480	1,879.0	831.0	467.0	299.0	208.0

Barrels per hour "B"	50	60	70	80	90	100
		Temperature, Degrees F=t				
80	8,934	2,234.0	993.0	559.0	358.0	248.0
90	10,460	2,615.0	1,162.0	654.0	419.0	291.0
100	12,030	3,010.0	1,338.0	752.0	483.0	336.0
150	20,670	5,184.0	2,298.0	1,293.0	824.0	576.0
200	30,340	7,584.0	3,360.0	1,898.0	1,213.0	842.0
250	41,030	10,270.0	4,577.0	2,567.0	1.642.0	1,140.0
300	52,070	13,030.0	5,790.0	3,264.0	2,083.0	1,447.0
350	63,940	16,000.0	7,110.0	4,000.0	2,567.0	1,778.0
400	76,400	19,100.0	8,480.0	4,770.0	3,060.0	2,120.0
450	89,400	22,400.0	9,950.0	5,600.0	3,590.0	2,480.0
500	103,000	25,700.0	11,400.0	6,430.0	4,130.0	2,730.0
550		29,200.0	12,980.0	7,300.0	4,670.0	3,245.0
600		32,740.0	14,600.0	8,190.0	5,250.0	3,650.0
650		36,500.0	16,220.0	9,130.0	5,840.0	4,055.0
700		40,300.0	17,900.0	10,080.0	6,470.0	4,480.0
750		44,160.0	19,630.0	11,040.0	7,070.0	4,910.0
800		48,100.0	21,400.0	12,030.0	7,710.0	5,340.0
850		52,260.0	23,300.0	13,060.0	8,360.0	5,810.0
900		56,300.0	25,000.0	14,100.0	9,031.0	6,270.0
1000		64,800.0	28,800.0	16,200.0	10,400.0	7,200.0

Friction of Heavy California Oil In Four-Inch Pipe Line

Barrels per hour "B"	110	120	130	140	150	160
		Temperature, Degree F=t				
5	4.53	3.35	2.74	2.22	1.85	1.54
10	11.4	8.43	6.9	5.58	4.79	3.88
15	19.6	14.5	11.9	9.59	8.01	6.67
20	28.8	21.2	17.4	14.1	11.8	9.77
25	38.7	28.6	23.4	19.0	15.8	13.2
30	49.4	36.5	29.9	24.2	20.2	16.8
35	60.6	44.8	36.7	29.7	24.8	20.6
40	72.5	53.5	43.8	35.5	29.6	24.6
45	84.8	62.6	51.3	41.5	34.6	28.8
50	97.6	72.0	58.9	47.7	40.0	33.3
60	125.0	91.9	75.2	60.9	50.8	42.3
70	153.0	113.0	92.4	74.8	62.4	52.0
80	183.0	135.0	110.0	89.4	74.6	62.1
90	214.0	158.0	129.0	105.0	87.3	72.6
100	246.0	182.0	149.0	120.0	101.0	83.6
150	423.0	312.0	255.0	207.0	173.0	144.0
200	621.0	458.0	375.0	304.0	253.0	211.0
250	839.0	621.0	506.0	410.0	343.0	285.0
300	1050.0	787.0	643.0	522.0	435.0	362.0
350	1310.0	967.0	791.0	640.0	534.0	445.0
400	1560.0	1150.0	944.0	765.0	637.0	531.0
450	1830.0	1390.0	1110.0	896.0	746.0	621.0
500	2100.0	1550.0	1270.0	1030.0	858.0	714.0
550	2390.0	1760.0	1442.0	1168.0	975.0	811.0
600	2680.0	1980.0	1620.0	1310.0	1100.0	909.0
650	2980.0	2210.0	1800.0	1460.0	1220.0	1020.0
700	3300.0	2430.0	1990.0	1610.0	1340.0	1120.0
750	3610.0	2670.0	2180.0	1770.0	1480.0	1230.0
800	3940.0	2910.0	2380.0	1930.0	1610.0	1340.0
850	4270.0	3150.0	2580.0	2090.0	1750.0	1460.0
900	4610.0	3390.0	2780.0	2250.0	1880.0	1570.0
1000	5310.0	3910.0	3200.0	2590.0	2170.0	1800.0

Friction of Heavy California Oil In Six-Inch Pipe

Barrels per hour "B"	Temperature, Degree F=t 50	60	70	80	90	100
10	73.6	18.4	7.0	4.6	3.0	2.05
15	126.0	31.6	14.0	7.9	5.06	3.51
20	186.0	46.3	18.6	11.6	7.42	5.15
25	250.0	62.4	27.7	15.6	10.0	6.96
30	318.0	79.6	35.4	20.0	12.7	8.84
35	391.0	99.7	43.5	24.4	15.7	10.9
40	467.0	117.0	51.9	29.2	18.7	13.0
45	547.0	137.0	60.7	34.2	21.9	15.2
50	628.0	157.0	70.0	39.3	25.2	17.5
60	802.0	201.0	89.1	50.2	32.1	22.3
70	985.0	247.0	110.0	61.6	39.4	27.4
80	1,177.0	294.0	131.0	73.6	47.1	32.7
90	1,377.0	344.0	153.0	86.0	55.1	38.0
100	1,585.0	396.0	176.0	99.1	63.6	44.3
150	2,723.0	683.0	303.0	170.0	109.0	75.9
200	3,995.0	999.0	443.0	250.0	160.0	111.0
250	5,404.0	1,353.0	603.0	338.0	216.0	150.0
300	6,857.0	1,715.0	763.0	430.0	275.0	191.0
350	8,420.0	2,107.0	936.0	527.0	338.0	234.0
400	10,060.0	2,516.0	1,117.0	628.0	403.0	280.0
450	11,780.0	2,946.0	1,311.0	738.0	472.0	327.0
500	13,550.0	3,388.0	1,505.0	847.0	544.0	377.0
600	17,250.0	4,310.0	1,918.0	1,079.0	691.0	481.0
700	21,220.0	5,306.0	2,360.0	1,328.0	851.0	590.0
800	25,350.0	6,338.0	2,820.0	1,585.0	1,016.0	704.0
900	29,660.0	7,417.0	3,296.0	1,854.0	1,188.0	826.0
1000	34,140.0	8,534.0	3,793.0	2,133.0	1,366.0	948.0
1200	43,530.0	10,880.0	4,838.0	2,723.0	1,740.0	1,210.0
1400	53,440.0	13,360.0	5,942.0	3,342.0	2,141.0	1,488.0
1600	63,900.0	15,970.0	7,098.0	3,992.0	2,554.0	1,774.0
1800	74,760.0	18,690.0	8,303.0	4,678.0	3,000.0	2,078.0
2000	86,000.0	21,510.0	9,560.0	5,378.0	3,443.0	2,390.0

Friction of Heavy California Oil In Six-Inch Pipe

Barrels per hour "B"	Temperature, Degree F=t 110	120	130	140	150	160
10	1.5	1.11	0.908	0.735	0.614	0.511
15	2.58	1.91	1.56	1.26	1.06	0.878
20	3.79	2.8	2.29	1.85	1.55	1.29
25	5.1	3.78	3.08	2.5	2.08	1.73
30	6.5	4.8	3.93	3.18	2.66	2.21
35	7.98	5.9	4.83	3.91	3.26	2.72
40	9.54	7.05	5.77	4.67	3.9	3.24
45	11.2	8.25	6.75	5.47	4.56	3.8
50	12.9	9.48	7.76	6.28	5.27	4.38
60	16.4	12.1	9.9	8.02	6.69	5.57
70	20.1	14.9	12.2	9.85	8.22	6.84
80	24.0	17.8	14.5	11.8	9.82	8.17
90	28.1	20.8	17.0	13.8	11.5	9.56
100	32.4	24.0	19.6	15.9	13.2	11.0
150	55.7	41.1	33.6	27.2	22.7	18.9
200	81.8	60.3	49.3	40.0	33.4	27.7
250	111.0	81.8	66.6	54.0	45.1	37.6
300	138.0	104.0	84.7	68.7	57.3	47.6

Barrels per hour "B"	Temperature, Degrees F=t 110	120	130	140	150	160
350	172.0	127.0	104.0	84.3	70.4	58.6
400	206.0	152.0	124.0	101.0	83.9	70.0
450	241.0	178.0	147.0	118.0	98.2	81.8
500	277.0	205.0	167.0	136.0	113.0	94.0
600	353.0	261.0	213.0	173.0	144.0	120.0
700	434.0	320.0	262.0	213.0	177.0	148.0
800	519.0	383.0	313.0	254.0	212.0	176.0
900	607.0	447.0	366.0	297.0	248.0	206.0
1000	700.0	514.0	422.0	342.0	285.0	237.0
1200	889.0	658.0	540.0	434.0	363.0	302.0
1400	1090.0	809.0	662.0	535.0	447.0	371.0
1600	1310.0	965.0	788.0	641.0	535.0	443.0
1800	1525.0	1130.0	923.0	750.0	624.0	519.0
2000	1760.0	1300.0	1060.0	860.0	721.0	599.0

Friction of Heavy California Oil In Eight-Inch Pipe

p=Pounds per square inch in One English Mile.

Barrels per hour "B"	Temperature, Degree F=t 50	60	70	80	90	100
25	59.2	14.8	6.58	3.7	2.37	1.65
50	149.0	37.3	16.6	9.33	5.97	4.15
75	256.0	64.1	28.5	16.0	10.3	7.12
100	376.0	94.0	41.8	23.5	15.1	10.5
150	646.0	162.0	71.8	40.4	25.8	18.0
200	948.0	237.0	105.0	59.3	37.9	26.3
250	1282.0	321.0	143.0	80.2	51.3	35.6
300	1627.0	417.0	181.0	102.0	65.1	45.2
350	1998.0	500.0	222.0	125.0	80.2	55.5
400	2387.0	597.0	265.0	149.0	95.5	66.3
450	2794.0	699.0	311.0	175.0	112.0	77.6
500	3215.0	804.0	357.0	201.0	129.0	89.3
600	4093.0	1023.0	455.0	256.0	164.0	114.0
700	5034.0	1259.0	560.0	315.0	202.0	140.0
800	6015.0	1504.0	669.0	376.0	241.0	167.0
900	7038.0	1760.0	782.0	440.0	282.0	196.0
1000	8100.0	2025.0	900.0	506.0	324.0	225.0
1100	9198.0	2300.0	1022.0	575.0	368.0	256.0
1200	10,330.0	2582.0	1148.0	646.0	413.0	287.0
1300	11,500.0	2874.0	1277.0	719.0	460.0	319.0
1400	12,680.0	3171.0	1410.0	793.0	508.0	353.0
1500	13,910.0	3477.0	1545.0	869.0	557.0	387.0
1600	15,160.0	3789.0	1684.0	947.0	606.0	421.0
1700	16,430.0	4109.0	1826.0	1027.0	658.0	457.0
1800	17,740.0	4435.0	1971.0	1110.0	712.0	493.0
1900	19,066.0	4765.0	2118.0	1191.0	763.0	530.0
2000	20,410.0	5103.0	2268.0	1276.0	817.0	567.0
2200	23,180.0	5794.0	2575.0	1449.0	927.0	644.0
2400	26,030.0	6506.0	2892.0	1627.0	1041.0	723.0
2600	28,960.0	7240.0	3218.0	1810.0	1158.0	805.0
2800	31,970.0	7994.0	3552.0	1998.0	1279.0	888.0
3000	35,050.0	8764.0	3895.0	2191.0	1406.0	974.0

Friction of Heavy California Oil in Eight-Inch Pipe

Barrels per hour "B"	Temperature, Degree F=t 110	120	130	140	150	160
25	1.21	0.894	0.731	0.592	0.494	0.411
50	3.05	2.25	1.84	1.49	1.25	1.04
75	5.23	3.87	3.16	2.56	2.14	1.78
100	7.68	5.68	4.64	3.76	3.14	2.61
150	13.2	9.74	7.97	6.46	5.39	4.49
200	19.4	14.3	11.7	9.48	7.91	6.58
250	26.2	19.4	15.8	12.8	10.7	8.91
300	32.6	24.6	20.1	16.3	13.6	11.3
350	40.8	30.2	24.7	20.0	16.7	13.9
400	48.8	36.0	29.5	23.9	19.9	16.6
450	57.1	42.2	34.5	28.0	23.3	19.4
500	65.7	48.5	39.7	32.2	26.8	22.3
600	83.6	61.8	50.5	40.9	34.2	28.4
700	103.0	76.0	62.2	50.4	42.0	35.0
800	123.0	90.8	74.3	60.2	50.2	41.8
900	144.0	106.0	86.9	70.4	58.8	48.9
1000	166.0	122.0	100.0	81.0	67.6	56.3
1100	188.0	139.0	144.0	92.0	76.8	63.9
1200	211.0	156.0	128.0	103.0	86.2	71.7
1300	235.0	174.0	141.0	115.0	96.0	79.8
1400	259.0	192.0	157.0	127.0	106.0	88.1
1500	284.0	210.0	172.0	139.0	116.0	96.6
1600	310.0	229.0	187.0	152.0	127.0	105.0
1700	336.0	248.0	203.0	165.0	137.0	114.0
1800	362.0	268.0	219.0	178.0	148.0	123.0
1900	389.0	288.0	235.0	191.0	150.0	133.0
2000	417.0	308.0	252.0	204.0	171.0	142.0
2200	473.0	350.0	286.0	232.0	194.0	161.0
2400	532.0	393.0	321.0	260.0	217.0	181.0
2600	592.0	437.0	358.0	290.0	242.0	201.0
2800	653.0	482.0	395.0	320.0	267.0	222.0
3000	716.0	529.0	433.0	351.0	293.0	244.0

Friction of Heavy California Oil in Ten Inch Pipe

p=Pounds per square inch in One English Mile.

Barrels per hour "B"	Temperature, Degree F.=t 50	60	70	80	90	100
50	48.8	12.2	5.44	3.06	1.96	1.36
75	83.9	21.0	9.34	5.25	3.38	2.33
100	123.0	30.8	13.7	7.7	4.95	3.44
150	212.0	53.1	23.5	13.3	8.46	5.9
200	311.0	77.7	34.4	19.5	12.4	8.62
250	420.0	105.0	46.9	26.3	16.8	11.7
300	533.0	134.0	59.3	33.4	21.4	14.8
350	655.0	164.0	72.8	41.0	26.3	18.2
400	782.0	196.0	86.9	48.9	31.3	21.7
450	916.0	229.0	102.0	57.4	36.7	25.4
500	1055.0	264.0	117.0	65.9	42.3	29.3
600	1342.0	355.0	149.0	83.9	53.8	37.4
700	1650.0	413.0	184.0	103.0	62.0	45.9
800	1971.0	493.0	219.0	123.0	79.0	54.4
900	2305.0	577.0	526.0	144.0	92.4	64.2
1000	2655.0	664.0	295.0	166.0	106.0	73.8

Barrels per hour "B"	Temperature, Degrees F=t 50	50	70	80	90	100
1100	3014.0	754.0	335.0	189.0	121.0	83.9
1200	3385.0	846.0	376.0	212.0	135.0	94.0
1300	3770.0	942.0	419.0	236.0	151.0	105.0
1400	4156.0	1040.0	462.0	260.0	167.0	116.0
1500	4560.0	1140.0	506.0	285.0	183.0	127.0
1600	4968.0	1242.0	552.0	310.0	199.0	138.0
1700	5385.0	1347.0	599.0	337.0	216.0	140.0
1800	5814.0	1454.0	646.0	364.0	234.0	162.0
1900	6246.0	1562.0	694.0	390.0	250.0	174.0
2000	6688.0	1672.0	743.0	418.0	268.0	186.0
2500	9054.0	2264.0	1006.0	566.0	362.0	252.0
3000	11490.0	2872.0	1276.0	718.0	461.0	319.0
3500	14100.0	3526.0	1567.0	882.0	564.0	392.0
4000	16860.0	4215.0	1873.0	1054.0	674.0	468.0
4500	19720.0	4932.0	2190.0	1233.0	789.0	548.0
5000	22700.0	5671.0	2522.0	1418.0	908.0	631.0

Friction of Heavy California Oil in Ten-Inch Pipe

P = Pounds per square inch in one English mile.

Barrels per hour "B"	Temperature, Degree F=t 110	120	130	140	150	160
50	1.0	0.737	0.603	0.488	0.41	0.341
75	1.72	1.27	1.04	0.839	0.701	0.583
100	2.52	1.86	1.52	1.23	1.03	0.855
150	4.33	3.19	2.61	2.12	1.77	1.47
200	6.36	4.69	3.84	3.11	2.59	2.16
250	8.59	6.36	5.18	4.2	3.51	2.92
300	10.7	8.06	6.59	5.34	4.46	3.7
350	13.4	9.9	8.1	6.56	5.47	4.56
400	16.0	11.8	9.67	7.83	6.52	5.44
450	18.7	13.8	11.3	9.18	7.64	6.36
500	21.5	15.9	13.0	10.6	8.78	7.31
600	27.4	20.3	16.6	13.4	11.2	9.31
700	33.8	24.9	20.4	16.5	13.8	11.5
800	40.3	29.8	24.4	19.7	16.5	13.7
900	47.2	34.8	28.5	23.1	19.3	16.2
1000	54.4	40.0	32.8	26.6	22.2	18.5
1100	61.6	45.6	37.4	30.2	25.2	21.0
1200	69.2	51.1	42.0	33.8	28.3	23.5
1300	77.0	57.0	46.2	37.7	31.5	26.2
1400	84.9	62.9	51.5	41.6	34.8	28.9
1500	93.1	68.8	56.4	45.6	38.0	31.7
1600	102.0	75.1	61.3	49.8	41.6	34.4
1700	110.0	81.3	66.6	54.1	44.9	37.4
1800	119.0	87.8	71.8	58.3	48.5	40.3
1900	128.0	94.4	77.0	62.6	52.1	43.6
2000	137.0	101.0	82.6	66.9	56.1	46.6
2500	185.0	137.0	112.0	90.6	75.6	62.9
3000	235.0	174.0	142.0	115.0	96.0	80.0
3500	288.0	213.0	174.0	141.0	118.0	98.0
4000	344.0	254.0	208.0	169.0	141.0	117.0
4500	403.0	298.0	244.0	197.0	165.0	137.0
5000	464.0	342.0	280.0	227.0	190.0	158.0

THE TRANSPORTING THROUGH PIPE LINES OF THE PETROLEUM OF PANUCO AND TOPILA FIELDS, MEXICO[1]

The formula of Poiseuille is applicable to petroleum.—It is known that so long as the viscosity of the oil does not reach a value called the "critical velocity," the formula of Poiseuille holds good in the movement of oil in pipe lines. The formula in common use is:

$$\frac{P}{L} = 1150 \frac{Q\ N}{D^4}$$

in which

P = loss of pressure in kilograms per square centimeter.
L = length of line in kilometers.
Q = output in cubic meters per hour.
N = absolute viscosity of oil.
D = diameter of pipe line in centimeters.

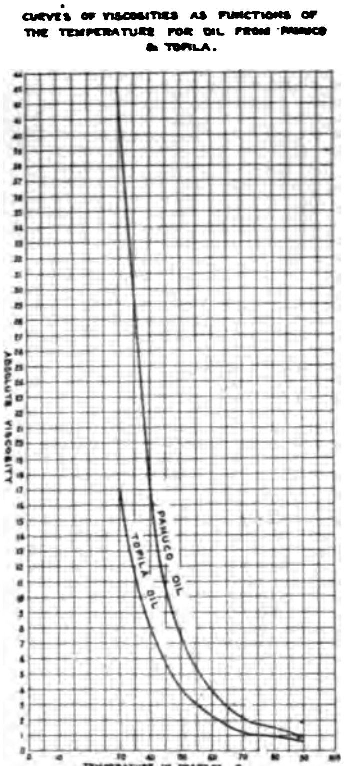


Fig. 149.

The English commission which experimented with our oils, found that under practical conditions they could not obtain the "critical velocity," and the same conclusion was reached while studying the working of the pipe line of the East Coast Oil Company from Topila to Tampico. It is almost certain that the systematic experiments which our Department of Petroleum has started in the camp of this company at Topila will lead to the same conclusions. As yet though the observations we have been able to make on the pipe line of the Mexican Gulf from Tepetate to Tampico have been limited, the results obtained incline us to the belief that the same formula of Poiseuille is applicable to this oil, less viscous than that of Panuco and Topila.

Influence of temperature.—As is

[1]By Juan Mancera in "Boletin del Petroleo"—Translation.

well known, the pressure is proportional to the viscosity, which in turn depends on the temperature. In Fig. 149 are shown the temperature-viscosity curves for the Topila and Panuco oils, prepared by "La Corona" Oil Company.

It can be seen that the viscosity is very sensible to the variations in temperature, especially for low temperatures, and it is easily understood how important this is in the calculations on the oil pipe lines.

Approximate formula for determining the decline in temperature in the length of the line.—The estimation of the variation in temperature with the length of the line can be made approximately through the theoretical formula which we have established:

Admitting that the heat which is lost is proportional to the time, to the contact surface and the difference in temperature between the oil and the earth, the heat which a volume of petroleum loses corresponding to that of a unit length of pipe in the time "dt" is:

$$a\ S\ (T\text{-}T_o)\ dt \text{ or } a\ S\ (T\text{-}T_o)\ d\,l$$

in which

a = an experimental coefficient.
S = exterior area of a unit length of pipe.
T = temperature of the oil.
T_o = temperature of the ground.
l = distance to "origin" of pipe line.
v = velocity of the oil.

The loss of temperature is obtained by dividing the loss of heat by the volume of oil, multiplied by its specific weight and by its specific heat.

$$dT = a\ \frac{S\ (T\text{-}T_0)\ dl}{v.\ w.\ d.\ o.}$$

in which w = the cross section area
d = specific gravity.
c = specific heat.

and

$$\frac{a.\ S.}{v.\ w.\ d.\ c.}\ dl = \frac{dT}{T - T_o}$$

$$\frac{a.\ S.}{v.\ w.\ d.\ c.}\ L = K - lg'.\ (T - T_o) \qquad \text{(Integrating?)}$$

For the starting point:

$$o = K - lg'. \ (T_1 - T_0)$$
$$K = Lg' \ (T_1 - T_0)$$

in which T_1 = The initial temperature of the oil.

$$\frac{a.\,S.}{f.\,w.\,d.\,c.} \, L = Lg' \, \frac{T_1 - T_0}{T - T_0}$$

$$\text{or} \quad \frac{a.\,S.}{Q.\,d.\,c.} \, L = Lg' \, \frac{T_1 - T_0}{T - T_0}$$

which is the formula sought for.

In an established pipe line, if we know S, 1, v, w, d, c, T_1, T_0 and T we are able to determine a. (The experimental factor).

When we take S in square meters per meter (unit) of length,

GRAPHS FOR SOLVING PROBLEMS OF VOLUMES IN PIPE LINES ACCORDING TO FORMULA OF POISEUILLE

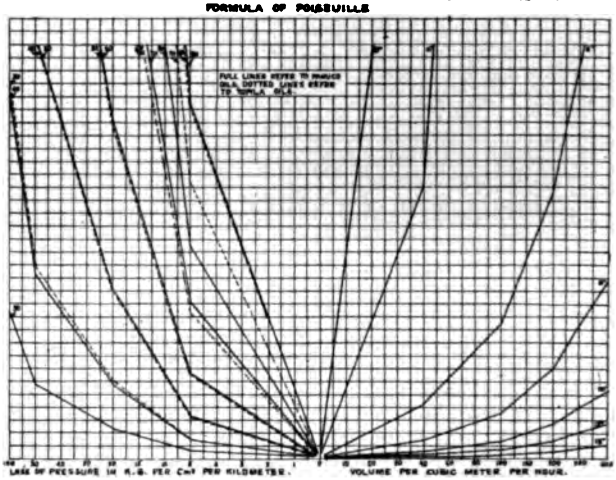


Fig. 150.

1 in kilometers, Q in cubic meters per hour and T in degrees Centigrade, a becomes equal to 2.7 according to the observations made on the East Coast Oil Company pipe line.

By means of this formula we are able to calculate the temperature of the oil at the discharge end of the pipe line, with the initial temperature fixed, less than the fire point; or better fixing the maximum temperature at the discharge end and determining the initial

(temperature), when it is desired to avoid the loss through evaporation which results from holding the hot oil at atmospheric pressure.

The formula was used also, with the corresponding coefficient, for investigating the loss of temperature in passing through streams of water. (This was determined in the pipe lines of the Standard Oil (Transcontinental) and the "El Aguila" which cross the Panuco River).

It is not possible to determine analytically the viscosity which should be employed in the formula of Poiseuille as well as the temperature corresponding to this viscosity since there is a definite curve for the equation between the temperature and the viscosity.

The loss of pressure per kilometer being a lineal function of "n," it is possible to determine a very approximate value for the average viscosity, according to the following method.

Having determined the logarithms of the temperatures, a curve of the viscosities is constructed, carrying a certain number of points, ordinates equal to the viscosities obtained from the curve T with respect to N, with the corresponding values of T taken from the first curve. The extreme points are joined with a continuous curve and the area between that curve, the abscissas and the extreme ordinates determined. The average viscosity is equal to this area divided by the length of the pipe line.

Proceeding in this manner, taking a number of cases with widely different conditions, one is able to verify the formula given the Commission by the Standard Oil Company of California as giving sufficiently accurate results.

According to that formula, the temperature corresponding to the average viscosity is obtained as a summation of two thirds parts of the final and one-third part of the initial temperature.

$$T \text{ equivalent} = \frac{T}{3} \text{ plus } \frac{2T_1}{3}$$

Graphs to solve problems of temperature, pressure and volume.—As the calculations are laborious two graphs have been constructed which have chiefly the advantage of determining in the solution of a problem, the effect of altering certain factors to obtain the most desirable solution.

In Fig. 152 to solve problems of temperature there is at the

right a series of vertical lines which correspond to the diameters of pipe in common use and a series of oblique, concurrent lines which represent volume in cubic meters per hour. By following across horizontally from the determined point of intersection of these lines to the left, until the vertical axis is encountered a corresponding one of the oblique lines which appear in the left hand

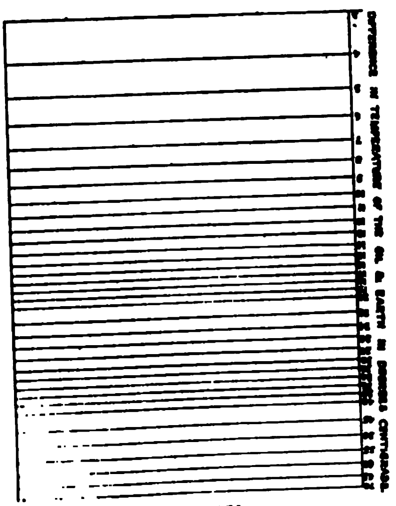


Fig. 151

tical line which corresponds to the distance to the origin of the pipe line or the length of the pipe line if one is seeking the final temperature.

The transparent paper accompanying this graph has a series of horizontals with figures which represent the difference in temperature between the earth and the oil in question. Placing this transparent paper in such manner that the upper horizontal line of the graph coincides with the difference in temperature between the oil at the initial point and the earth, the point determined in the graph (i. e. length of line) will fall on the horizontal marked with the

difference in temperature between the oil and the earth at the point sought.

On the right side of Fig. 150 to solve the problems of pressure and volume there is a series of vertical lines marked at the bottom with volume in cubic meters per hour the broken lines represent commercial diameters. The intersection of one of these broken lines with a vertical determine a horizontal which should be followed to the left until it meets the broken line marked with the corresponding temperature (Panuco oil in solid lines, Topila in dashed lines). From the point of intersection follow the corresponding vertical line to the bottom horizontal upon which is marked the loss in pressure in kilos. per sq. centimeter per kilometer of line.

It is clearly seen that one may proceed in an inverse manner (from left to right).

The graph for temperature was constructed with the value 2.7 for the coefficient of transmission determined by " La Corona," from the observations made on the pipe line of the East Coast Oil Company. I believe that this value is somewhat exaggerated and for this reason constructed also the dotted lines which correspond to a value of 2.3, the average of these observations.

For other oils I believe one should use this curve taking as an assumed temperature that temperature of the Panuco oil that corresponds to the viscosity the new oil has at the pumping temperature.

It should also be noted in ending that the greater part of the companies in calculating their pipe lines have employed the formula of Bowie which should not be employed, at least when dealing with Panuco, Topila and Tepetate oils.

If we wished to verify this a simple and rapid test could be made as follows: Pump at a pressure of 28 kilos. per sq. cm (400 lbs. per sq. inch) and measure carefully the stroke of the pistons and the number of strokes to determine the quantity. Afterward, not changing the temperature in the pipe line, double the pressure and again calculate the volume.

If the Bowie formula is to be verified the volume should show an increase in the ratio of 1 to 1.41. If Poiseuille is verified, the volume should be doubled.

Problem No. 1.—In an 18 kilometer pipe line of 203 mm (8″) di-

ameter, if Panuco oil is heated to 770° C. (170°F.) and a pjressure of 56 kilogrames per square centimeter is applied (800 lbs. per square inch) at what temperature is the oil delivered and what amount of oil will pass per hour?

To solve a problem like this we must begin by taking an assumed value, for instance, let us assume a temperature equivalent to 60°.

The loss of pressure per kilometer is:

$$\frac{56}{18} = 3.11$$

In Fig. 150, after finding the intersection of line corresponding to Panuco oil at 60° with the vertical corresponding to 3.11, the horizontal line to the right is followed until you find the line 8″; following down the vertical the approximate volume of 115 m^3 is found.

Let us suppose that the average temperature of the earth is estimated at 25° C, so that the excess of temperature at starting point is

$$77 - 25 = 52° \text{ C}$$

Placing the thin paper on Fig. 152 in a way that line 52 coincides with the upper horizontal, the horizontal line is followed from the intersection of line 8″ with line 115 m^3 of volume (interpolating by eye) to the left and then the oblique line until the vertical of 18 kilometers is found, at a point that in the transparent paper corresponds to 24°. The final temperature of the oil is 24 plus 25 = 49° C. (120°F).

The average temperature would be

$$\frac{77}{3} + \frac{2 \times 49}{3} = 58° \text{ C approximately}$$

Correcting the estimate of volume with this temperature there is found a volume a little over 100 cubic meters per hour (15,000 barrels per day).

Problem No. 2.—A pipe line of 24 kilometers length and 254 millimeters diameter (10″) must have a capacity of 200 cubic meters per hour. It is desired that the oil reach the terminal station at a temperature not above 50° C. What pressure must be applied and at what temperature must the oil be heated at the initial station?

Let us assume that the temperature of the subsoil is estimated to be 26° C.

On the right side of Fig. 152 find the intersection of vertical 10" with the obliques corresponding to a volume of 200; from the point of intersection follow the horizontal line to the left to the corresponding oblique, which is then followed to its intersection with the vertical "24 kilometers." The transparent paper is placed in a way that the horizontal 50-26 = 24 passes over the intersec tion point obtained. The upper horizontal falls upon the temperature 48, so that the initial temperature will be 48 plus 26 = 74°C.

The average temperature is:

$$\frac{74}{3} + \frac{50x2}{3} = 58° \text{ C}$$

On Fig. 150, starting from the intersection of the lines representing 10" and 200 cubic meters follow to the left, to meet temperature 58 degrees and then follow the vertical down. The loss of pressure per kilometer is found to be 2.25 kilogrames per square centimeter. The initial pressure will be 2.25x24=54 k. per cm.² (770 lbs. per square inch).

Friction Loss In Pipe Lines Due To Elbows.

Friction loss due to elbows is commonly considered in terms of an equivalent length of straight pipe. The following table gives the commonly accepted equivalent lengths. It will be noted from it that five 6-inch elbows in a 6-inch pipe line would be equivadent to extending the straight length of pipe 120 feet.

Nominal Diameter of Elbow Inches	Equivalent Length of Straight Pipe Feet
16	63
14	57
12	49
10	42
8	32
6	24.0
5	19.0
4	14.0
3½	11.5
3	9.3
2½	6.7
2	5.1

OIL ENGINES IN PIPE LINE PUMP STATIONS

By H. R. LUCKE

Throughout the United States, but particularly in the Mid-Continent and Gulf Coast territories, crude oil burning engines are used extensively for operating pipe line pumps. The cost of pumping oil with this class of equipment is extremely low.

Early installations.—Probably the earliest use of oil engines for pipe line use was by the National Transit Pipe Line in Pennsylvania. The engines used would seem crude according to present practice, but they gave good service. They were of the hot surface type and low compression. Constant service was not required. The operators would fill the fuel tank with a measured quantity of oil which would serve the engine for the period required, then leave it to shut down when this fuel had been consumed and the required work performed.

The first large installation of oil engines on pipe lines was for the Tidewater Pipe Line, by the De La Vergne Machine Company on the results of the few small engines used by the National Transit Pipe Line. These engines were the horizontal "Type H. A.", built under license from Messrs. Hornsby & Sons of Gratham, England,

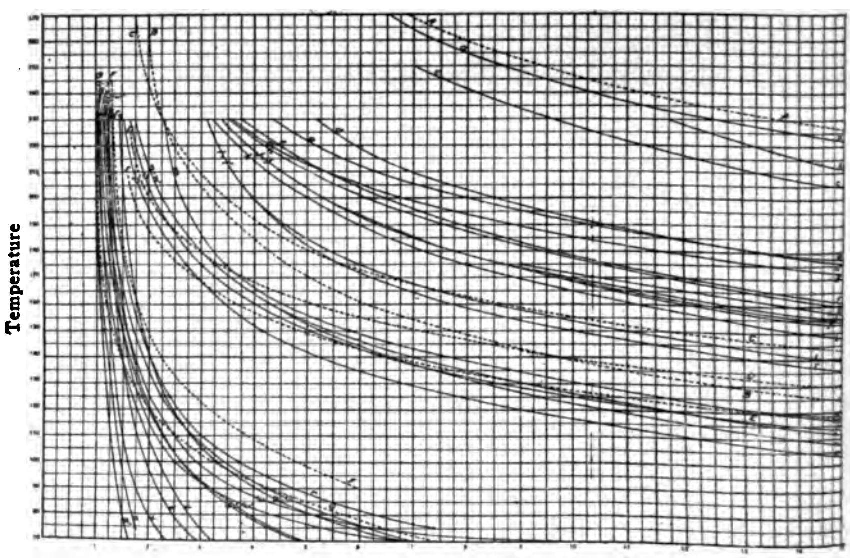


Fig. 153.—Temperature—Viscosity Diagram for Oil Fuel[1].

[1]From United States Bureau of Mines Oil Fuel Handbook.

EXPLANATION OF CURVES IN FIG. 153

Curve No.	Type of oil	Gravity Specific	Gravity ° B.	Flash point, ° F.
	Solid curves			
a	Mexican residue	1.000	10.0	374
b	"Toltec fuel oil," Inter-Ocean Oil Co., N. Y.	.988	11.7	220
c	"Toltec or Panuco oil," Inter-Ocean Oil Co.	.986	12.0	124
d	"No. 102," Union Oil Co., Bakersfield, Cal.	.980	12.9	280
e	"No. 18," Union Oil Co., Bakersfield, Cal.	.980	12.9	285
f	"Standard" Mexican crude (lot 2)	.964	13.4	202
g	"No. 25," Union Oil Co., Bakersfield, Cal.	.978	13.2	262
h	Mexican crude, Texas Co.	.952	17.3	126
i	Sample No. 3, Anglo-Mex. Pet. Products Co.	.952	17.3	164
j	"Gaviota Refinery," Associated Oil Co., California	.953	17.1	230
j'	Mexican oil, Atlantic torpedo flotilla, March, 1914	.947	18.1	182
k	Standard Mexican crude (lot 1)	.954	17.0	145
l	Mexican oil, U. S. S. Arethusa	.950	17.6	182
l'	"Nos. 1, 2, 3," Anglo-Mexican Pet. Products Co.	.955	16.8	188
m	Producers Crude No. 1 fuel oil, Union Oil Co., Cal.	.959	16.1	174
n	"Coalinga Field." Associated Oil Co., Monterey, Cal.	.957	16.5	186
n'	"Avon Refinery," Associated Oil Co., Avon, Cal.	.953	17.1	168
o	Richmond, California	.953	17.1	228
p	Sun Co., Louisiana	.936	19.8	275
q	"Standard," Illinois	.893	27.3	146
r	Gulf Ref. Co., Navy standard oil, U. S. S. Perkins	.892	27.5	180
s	"Standard," Indiana	.880	29.6	144
t	"Standard Star," California	.912	23.9	180
u	"Standard," Illinois (lot 4)	.893	27.3	146
v	"Standard," Indiana (lot 4)	.880	29.6	144
w	Gulf Refining Co., Navy contract	.882	29.3	170
w'	"Standard," Lima, Ohio, crude	.876	30.4	149
x	Camden Chemical Co., by-products of coal tar.			
y	"Star," California	.912	23.9	180
z	Gulf Refining Co., Navy standard oil, U. S. S. Roe	.885	28.7	182
z'	Standard Mexican gas oil	.856	34.2	151
•	Indicates test results.			
	Dotted curves			
A	Panuco crude, Inter-Ocean Oil Co.	.975	13.7	140
B	Mexican petroleum, Texas Co.	.938	19.5	234
C	Associated Oil Co., California	.971	14.2	257
D	Bakersfield, Cal. pipe line to Port Costa	.970	14.4	260
E	California Standard Oil Co., steamer Santa Barbara	.962	15.7	282
F	Beaumont, Tex., Gulf Refining Co.	.907	24.8	222
G	Navy standard oil, Texas Co.	.911 to .900	24 to 26	195 to 220

and called by them the "Hornsby-Akroyd," Akroyd being the name of the inventor.

Subsequent to the Tidewater Pipe Line installations, the Gulf Pipe Line Company equipped their 550-mile pipe line from the Glenn Pool to Port Arthur with "Type H. A." engines, all of which are still in operation 24 hours per day. These engines have shown the remarkable record of an average of better than 98½ per cent service for a period of over eleven years, running 24 hours per day.

The development of engines burning heavy oil.—The developments of more economical steam pumps and the production of crude and fuel oils too heavy for practical use in the "Type H. A." engine disclosed the necessity for a new engine to compete with the changing conditions. The De La Vergne Machine Company

then introduced their "Type F. H." engine known to them as the Franchetti Horizontal and designed by Mr. Allesandro Franchetti, an Italian. It was long known that to get better results from the "H. A. Engine" it would be necessary to increase compression, but with that system it would be necessary to retard combustion. Mr. Franchetti conceived the idea of injecting the fuel at the end of the compression stroke which was the only solution. Dr. Rudolph Diesel had already secured patents on the engine bearing his name and involving this method, but depending entirely on the heat of a high compression for ignition. Mr. Franchetti then used a combination of the Diesel principle and "H. A." principle and injected the fuel into a chamber surrounded by an unjacketted preheated surface as in the H. A. Engine, but at the end of the compression stroke. This permitted carrying compression to any point desired and also the use of lower grade fuels. As with the Diesel engine the fuel was introduced by compressed air. The consumption of fuel was reduced from one pound per h. p. hour in the "H. A." engine to six-tenths of a pound in the "F. H." engine.

Later installations.—The first notable installation of "F. H." engines was on the Standard Oil Company of Louisiana Pipe Line, and followed by the Oklahoma Pipe Line Company, the Magnolia Petroleum Company pipe line and the Prairie Pipe Line Company.

Attracted by the constantly increasing business of the De La Vergne Machine Company with the oil pipe lines, other manufactures entered into competition, most of whom offered Diesel engines manufactured under European licenses, as it was in Europe the Diesel engine was being perfected. Notable among these is the Snow Engine, manufactured by the Snow Steam Pump Company of Buffalo, New York. Most of their early installations were two cycle horizontal Diesel engines, but they early discarded the two cycle engine in favor of the four cycle. Their first installations of note were on the Prairie Pipe Line, and probably the principal reason was that it was then believed that a fire wall between the engine and pump rooms could be dispensed with. With engines using hot surface ignition an open torch was used for preheating which could not be done in the same room with the pumps because of the fire hazard.

The next notable purchases of oil engines was by the Sinclair Cudahy Pipe Line, which was equipped with Busch Sulzer Broth-

ers Diesel Engines and Snow Diesel Engines and then by the Yarhola Pipe Line Company, which was equipped with Allis-Chalmers Diesel Engines.

At about this time the McIntosh & Seymour Corporation of Auburn, New York, entered this field and they have now installed a number of their vertical Diesel engines on the Sinclair lines, Prairie pipe lines, Standard Oil Company of Louisiana pipe line, and the Humble Pipe Line Company's lines. These installations range from 150 to 665 h. p. per engine.

For the last several years practically all oil engines purchased for trunk pipe line use have been of the straight Diesel type, except where purchases were made to add to plants already equipped with other types. Until recently the horizontal engine has been most in favor, but during the last two years (1919-1921) probably 85 per cent of the oil engine power installed on oil pipe lines has been of the vertical multi-cylinder Diesel type, which is an indication that the prejudice in favor of horizontal engines no longer exists. It is also a noteworthy fact that all of the builders of horizontal engines are now engaged in building vertical engines, excepting possibly the Allis-Chalmers Company.

Other types of engines in use in a small way for oil pipe line power are the De La Vergne "Type D. H.," the Solid Injection Diesel engine, and the so-called "Semi-Diesel."

Typical installations.—The engines are used direct geared to power pumps of either the vertical triplex or horizontal duplex pattern. They are installed of sufficient size so that they operate at only about 75 per cent of their rated horse power. Typical installations will be discussed.

At Sour Lake, Texas, The Texas Company has four 150 h. p. Snow oil engines, each direct geared to 8¾x12 Goulds vertical triplex power pumps. Two additional engines are being installed (December, 1920). Each of these have a capacity of 350 barrels per hour in pumping to Nederland or Port Arthur. The initial pipe line pressure used varies from 350 to 700 pounds per square inch, depending on the quality of oil being pumped. Lubricating oil filters and reclaimers are used. The approximate amount of lubricating oil used per day, per engine, averages around two quarts. It is reported that no unit in this station has stopped, except at the regular 90-day period, when a general inspection and

overhauling is given each unit. Outside of this, they operate constantly (24 hours per day, 365 days per year).

In this same district the Magnolia Petroleum Company uses De La Vergne 100 and 150 h. p. engines direct geared to National Transit Company vertical triplex and horizontal duplex power pumps. Their Hull station, containing three 100 h. p. and three 150 h. p. units, is reported to operate on 8 to 10 barrels of fuel per day.

The Gulf Pipe Line Company uses the De La Vergne engines very extensively but also has in use several seventy-five 85 h. p. Bessemer engines.

The Humble Pipe Line Company is reported to be getting very good service out of McIntosh & Seymour vertical multiple cylinder engines. They also have in operation at Hull, Texas, a 90 h. p. Ingersoll-Rand low compression vertical oil engine.

OPERATION AND ADJUSTMENT OF DIRECT-ACTING STEAM PUMPS[1]

Setting steam valves on duplex pumps.—The general rule for setting the valves is to place the pistons, on both sides, at the center of the stroke and set the steam valves in central position with relation to the ports. As there is no lap, the outer edges of the valves will be flush with the outer edges of the ports.

In this position the valve rod clearance or the lost motion must be divided evenly, so as to have the same amount of lost motion on either side of the valve or at either end of the lost-motion link. The total lost motion may be made equal to three-tenths of the travel of the crank pin at contact stroke and can later be adjusted if the pump is not working properly.

To place the pistons at the center of the stroke, move them first to contact with one head and then to the other, each position being marked on the rod against the glands. Then place a mark midway between these two marks and move the rod until this central mark comes against the edge of the gland. This having been done on both sides, the pistons are in central position in which the valve motion arms should stand perpendicular. If this is not the case the crosshead must be disconnected and the position corrected.

[1]From Nickel's "Direct Acting Steam Pumps"—McGraw-Hill.

Now remove the steam chest covers and place the slide in a position central to the ports, and adjust the lost motion so as to have the same clearance on either end. If the steam end is equipped with rotary valves a mark should be made on the hub of the crank and a corresponding one on the bearing to indicate the line-on-line position. This will save the frequent removal of the bonnets and will be a ready means of detecting any shifting. On very long pumps it is well to set the valves while the cylinders are hot, because the expansion of the steam end may throw out the setting.

Setting up pumps.—In erecting a pump always be sure that it is so connected as to provide a full and uniform supply of the liquid to be handled. To accomplish this the suction pipe should be large so as to reduce the velocity, 3 to 4 feet per second being proper in a short pipe. The diameter of a long pipe should be made larger to allow for the increased friction.

The suction pipe should be as short as possible and few bends, such as are necessary being of long radius. A suction well close to the pump and connected to the water supply by a conduit is preferable to a long suction pipe. Care must be taken to maintain a uniform grade in laying the pipe to avoid air pockets. Test the pipe to 25 pounds before covering, as small air leaks will prevent the proper working of the pump.

In all cases where a pump is to lift water by suction it will be found convenient to provide a priming pipe leading to the pump chambers; or, if the suction pipe is provided with a foot valve, this priming pipe may be led to the suction chambers. A relief valve should then be attached to protect the foot valve. Hot water can not be lifted by suction.

In connecting the steam pipe make due allowance for expansion. Place a throttle valve in the pipe close to the pump and provide means for draining the pipe with the throttle valve closed. Before connecting the pump, blow out the steam pipe thoroughly to keep dirt from getting into the steam cylinders.

After stopping the pump, open all blow-off and drain valves. If it is to be idle for some time open the cock of the oil cup, so as to let the oil flow into the steam chest; then let the pump make a few clean strokes to distribute the oil well over the inside of the steam end. This will prevent rusting.

Keep the stuffing-boxes well packed with a good quality of

packing. Screw up the gland no tighter than is necessary to prevent leakage ,and renew the packing before it becomes hard. Watch the rod and the outside-packed plungers to detect any cutting.

Operating direct-acting pumps.—On small pumps a pet cock is provided on the discharge chamber for blowing out the air. On larger pumps a regular valve, the starting or waste valve, should be placed on the discharge pipe, inside of the gate and check valves. Prime and start the pump with the waste valve open, so as to work the air out of the pump chambers. If there is a check valve, this will open automatically when the right speed is reached; but if there is only a gate valve with pressure on the outside, a gage should be placed at some point inside the gate valve. If the pump is then started, discharging through the waste valve, the gage will indicate the point at which the pressures inside and outside of the gate valve are balanced; then the gate valve may be opened.

It is essential that both sides of a duplex pump be packed exactly alike; otherwise on eside will travel faster than the other.

Rules for starting large condensing pumps.—

1. Turn on the jacket steam so as to thoroughly heat the cylinders.
2. Prime the pump bodies.
3. Start the air pump (if independent).
4. Open the throttle valve slowly. On a triple-expansion pump also open the live steam valve.
5. When the pump is under way, close the live steam valve and open the throttle valve until normal speed is obtained.
6. Adjust the cutoff valves, cushion valves and cross-exhaust valves until the pump is running smoothly at full stroke.

Do not allow a pump equipped with a surface condenser to run without water, as the exhaust steam will burn out the tube packing.

Cushion valve.—Closing the cushion valve shortens the stroke. It is generally better to run with these partly open to soften the cushion.

Cross-exhaust valves.—Opening these lengthens the stroke. In a triple-expansion engine one of the two must generally be partly or fully open in order to equalize the action of the two sides of the machine. When running very slowly it may be necessary to open

both valves to maintain full stroke. Never open the intermediate cross exhaust until the high-pressure cross exhaust has been fully opened. The economy will be less with the cross-exhaust valves open and the loss will be greater with the intermediate-pressure valve open than with the high-pressure valve open.

Cutoff adjustments.—Triple-expansion engines are equipped with cutoff valves on the high-pressure cylinders, for the purpose of adjusting the stroke economically. If there are no guide marks on the links, note their direction of motion and that of the piston. and note whether the link is pushing the valve closed or pulling, when the piston is nearing the end of the stroke. If pushing, the cutoff is shortened by lengthening the link; if pulling, by shortening the link. This adjustment can be made while the pump is in motion. When properly adjusted the pump should make the normal stroke with equal clearances at each end.

Operating Worthington high-duty pumps.—The steam valves can not be set without instructions from the manufacturer and a diagram.

The pump is always started low duty, that is, with the cutoffs out of commission, so as to admit steam the full length of the stroke. When the engine is under way, the cutoffs are thrown in. Separate adjustments for the cutoff on each end of each cylinder is provided to control the travel at the four corners and to equalize the clearances.

The packing of the compensating cylinders and the accumulating ram needs careful attention, so as to be tight against the high pressure without undue friction. Moreover, the air piston of the accumlator should be kept flooded with oil to prevent excessive air leakage.

Open the pet cocks on the compensating cylinders occasionally to let the air out and prevent an explosion should the pump make a quick stroke. Keep the air chamber well supplied with air and the accumulator piston in a central position.

CHAPTER VII

TANKS

THE STRAPPING OF OIL STORAGE TANKS AND PREPARATION OF GAGING TABLES

The accuracy attempted and the detail gone into in the preparation of tank tables varies with the value of the product being handled. In the Mid-Continent fields, where the market price of crude oil reaches as high as $4.50 per barrel, much more detail is required than in the Gulf Coast region or in the Mexican fields where fuel oil prices get as low as 75 cents per barrel. In making up tables for tanks in which refined products are stored even more accuracy is needed. In preparing tank tables where too much accuracy is not required the following formula is used quite extensively:

Capacity of any round tank in barrels per inch of depth equals $C^2 \times .00118115$

where C equals the inside circumference of the tank in feet. The inside circumference is found by making a deduction for the thickness of stave or steel plate from the measured outside circumference. These deduction s will be as follows:

DEDUCTIONS WOOD STAVES

Thickness inches	Deduction
1— 0 .	0.52
— 1/16	0.56
— 1/8	0.59
— 3/16	0.62
— 1/4	0.65
— 5/16	0.69
— 3/8	0.72
— 7/16	0.75
— 1/2	0.78
— 9/16	0.82
— 5/8	0.85
—11/16	0.88
— 3/4	0.91
—13/16	0.95
— 7/8	0.98

DEDUCTIONS STEEL TANKS

Gauge	Thickness inches	Deduction
11	1/8	.0653
10	9/64	
9	5/32	.0817
8	11/64	
7	3/16	.0983
6	13/64	
5	7/32	.1147
4	15/64	
3	1/4	.1310
2	17/64	
1	9/32	.1473
0	5/16	.1637
00	11/32	.1800
3—0	3/8	.1963
4—0	13/32	.2127

Thickness inches	Deduction	Gauge	Thickness inches	Deduction
—15/16	1.01	5—0	7/16	.2290
2— 0	1.04	6—0	15/32	.2454
— 1/16	1.08	7—0	1/2	.2617
— 1/8	1.11			
— 3/16	1.15			
— 1/4	1.18			
— 5/16	1.21			
— 3/8	1.24			
— 7/16	1.27			
— 1/2	1.31			
— 9/16	1.34			
— 5/8	1.37			

As a general rule the following formulas will be found useful in preparing tank tables and in checking computations:

Capacity of Cylindrical tanks in barrels of 42 gallons—

Per inch of depth = (Inside circumfer. in ft.) ^{2} x .00118115
Per ¼ inch of depth = (Inside circumfer. in ft.) ^{2} x .00029529
Per foot of depth = (Inside circumfer. in ft.) ^{2} x .01416

$$\text{Total capacity} = \frac{(\text{Inside diam. in ft.})^2 \times (\text{Depth in ft.})}{7.15307}$$

Capacity of rectangular tanks in barrels of 42 gallons—

Per ¼ inch of depth = Inside area base in sq. ft. x .003704

Wooden tanks.—Wooden tanks are shaped like frustrums of cones and circumference measurements are usually taken with steel tape. The first measurement is taken six inches above the bottom of the tank and other measurements are taken every two feet of height thereafter. Intermediate circumferences are gotten by interpolating. The position of the bottom of the tank is ascertained by measuring up underneath the tank until the bottom is encountered and adding 2 inches for its thickness. Should the hoops interfere with regular two-foot measurements the measurements can be taken at convenient points and interpolations made for the regular two foot measurements. The depth of the tank is then measured and the space occupied by the vertical roof supports is calculated. The following is an example of a set of notes taken in the field in the strapping of a 1600 barrel wooden tank:

CONTENTS OF TANKS—BARRELS PER INCH.

CIR. FEET	.00	.05	.10	.15	.20	.25	.30	.35	.40	.45	.50	.55	.60	.66	.70	.75	.80	.85	.90	.95	CIR. FEET
14	.231	.233	.234	.236	.238	.240	.241	.243	.245	.247	.249	.250	.252	.254	.255	.257	.259	.260	.262	.264	14
15	.265	.267	.269	.270	.272	.274	.276	.278	.280	.281	.283	.285	.287	.289	.291	.293	.295	.297	.299	.300	15
16	.302	.304	.306	.308	.310	.311	.313	.315	.317	.319	.321	.323	.325	.327	.329	.331	.333	.335	.337	.339	16
17	.341	.343	.345	.347	.349	.351	.353	.356	.358	.360	.362	.364	.366	.368	.370	.372	.374	.376	.378	.380	17
18	.383	.385	.387	.388	.390	.392	.394	.396	.398	.400	.403	.405	.407	.410	.412	.415	.418	.420	.422	.424	18
19	.426	.428	.430	.432	.434	.437	.439	.441	.443	.445	.448	.450	.453	.455	.458	.460	.463	.466	.468	.470	19
20	.472	.475	.477	.480	.482	.485	.487	.489	.491	.493	.495	.498	.500	.503	.505	.508	.510	.512	.515	.518	20
21	.521	.523	.525	.528	.530	.533	.535	.538	.540	.542	.545	.548	.550	.553	.556	.559	.561	.564	.566	.569	21
22	.571	.573	.576	.579	.582	.585	.587	.590	.592	.595	.598	.601	.603	.606	.608	.611	.613	.616	.619	.622	22
23	.625	.627	.630	.632	.635	.638	.641	.644	.647	.650	.653	.655	.658	.660	.663	.666	.668	.671	.674	.677	23
24	.680	.683	.686	.688	.691	.694	.697	.700	.703	.706	.709	.712	.715	.718	.721	.724	.726	.729	.732	.735	24
25	.738	.741	.744	.747	.750	.753	.756	.759	.762	.765	.768	.771	.774	.777	.780	.783	.786	.789	.792	.795	25
26	.798	.801	.804	.807	.810	.814	.817	.821	.824	.827	.830	.833	.836	.839	.842	.845	.848	.852	.855	.858	26
27	.861	.864	.867	.870	.874	.877	.880	.884	.887	.890	.893	.896	.900	.903	.906	.909	.912	.916	.920	.923	27
28	.926	.930	.933	.936	.939	.942	.945	.949	.952	.956	.959	.963	.966	.970	.973	.976	.980	.983	.987	.990	28
29	.993	.997	1.000	1.004	1.007	1.010	1.014	1.017	1.021	1.024	1.028	1.031	1.035	1.039	1.042	1.045	1.049	1.052	1.056	1.060	29
30	1.063	1.066	1.070	1.074	1.077	1.080	1.084	1.087	1.091	1.095	1.099	1.102	1.106	1.110	1.113	1.117	1.121	1.124	1.128	1.131	30
31	1.135	1.139	1.142	1.146	1.150	1.154	1.157	1.161	1.165	1.168	1.172	1.175	1.179	1.183	1.187	1.191	1.195	1.198	1.202	1.206	31
32	1.209	1.213	1.217	1.220	1.224	1.228	1.232	1.236	1.240	1.244	1.248	1.251	1.255	1.258	1.263	1.267	1.271	1.275	1.278	1.282	32
33	1.286	1.290	1.294	1.298	1.302	1.306	1.309	1.313	1.317	1.321	1.325	1.329	1.333	1.337	1.341	1.345	1.349	1.353	1.357	1.361	33
34	1.365	1.369	1.373	1.378	1.382	1.385	1.389	1.393	1.397	1.401	1.405	1.409	1.413	1.418	1.422	1.426	1.430	1.434	1.438	1.442	34
35	1.446	1.450	1.454	1.459	1.463	1.467	1.471	1.475	1.479	1.484	1.488	1.492	1.497	1.501	1.505	1.509	1.513	1.518	1.522	1.527	35
36	1.531	1.535	1.539	1.543	1.547	1.552	1.556	1.560	1.564	1.569	1.573	1.577	1.582	1.586	1.591	1.595	1.600	1.604	1.609	1.613	36
37	1.617	1.622	1.626	1.630	1.634	1.638	1.643	1.647	1.652	1.657	1.661	1.666	1.671	1.675	1.679	1.684	1.689	1.693	1.697	1.701	37
38	1.705	1.710	1.715	1.719	1.724	1.728	1.733	1.737	1.742	1.747	1.751	1.756	1.760	1.765	1.769	1.774	1.779	1.783	1.787	1.792	38
39	1.796	1.800	1.805	1.810	1.815	1.820	1.825	1.829	1.834	1.839	1.843	1.848	1.852	1.857	1.861	1.866	1.870	1.875	1.880	1.885	39
40	1.890	1.894	1.899	1.903	1.908	1.914	1.918	1.923	1.928	1.933	1.937	1.942	1.946	1.951	1.956	1.961	1.966	1.971	1.976	1.981	40
41	1.986	1.990	1.995	1.999	2.004	2.009	2.014	2.019	2.024	2.029	2.034	2.039	2.044	2.049	2.054	2.059	2.064	2.069	2.074	2.079	41
42	2.084	2.088	2.093	2.098	2.103	2.108	2.112	2.117	2.122	2.127	2.133	2.138	2.144	2.149	2.154	2.159	2.164	2.169	2.174	2.179	42
43	2.184	2.189	2.194	2.199	2.204	2.209	2.214	2.219	2.224	2.229	2.235	2.240	2.245	2.251	2.256	2.261	2.266	2.271	2.276	2.282	43
44	2.287	2.292	2.297	2.302	2.308	2.313	2.318	2.323	2.328	2.333	2.338	2.343	2.349	2.354	2.360	2.365	2.370	2.376	2.381	2.386	44
45	2.392	2.397	2.403	2.408	2.413	2.419	2.424	2.429	2.434	2.440	2.445	2.451	2.456	2.461	2.466	2.472	2.477	2.483	2.488	2.494	45
46	2.499	2.505	2.510	2.516	2.521	2.527	2.532	2.538	2.543	2.548	2.554	2.560	2.565	2.571	2.576	2.581	2.587	2.592	2.598	2.604	46
47	2.609	2.615	2.620	2.626	2.631	2.637	2.643	2.648	2.654	2.659	2.665	2.671	2.676	2.682	2.687	2.693	2.699	2.705	2.711	2.717	47
48	2.722	2.728	2.733	2.739	2.744	2.750	2.756	2.761	2.767	2.772	2.778	2.783	2.789	2.795	2.801	2.807	2.813	2.819	2.824	2.830	48
49	2.836	2.842	2.848	2.854	2.859	2.865	2.871	2.876	2.882	2.888	2.894	2.899	2.904	2.910	2.917	2.923	2.929	2.935	2.941	2.947	49
50	2.953	2.959	2.966	2.971	2.977	2.983	2.988	2.994	3.000	3.006	3.012	3.018	3.024	3.030	3.036	3.042	3.048	3.054	3.060	3.067	50
51	3.073	3.079	3.084	3.090	3.096	3.102	3.108	3.114	3.120	3.127	3.133	3.139	3.145	3.152	3.158	3.164	3.170	3.176	3.182	3.188	51
52	3.194	3.200	3.206	3.212	3.218	3.225	3.231	3.237	3.243	3.250	3.256	3.262	3.269	3.275	3.281	3.287	3.294	3.300	3.306	3.312	52
53	3.318	3.324	3.331	3.337	3.343	3.349	3.355	3.362	3.368	3.375	3.381	3.387	3.394	3.400	3.407	3.413	3.419	3.425	3.432	3.438	53
54	3.444	3.450	3.457	3.463	3.469	3.476	3.482	3.489	3.495	3.501	3.508	3.515	3.521	3.528	3.534	3.541	3.548	3.554	3.560	3.566	54
55	3.572	3.579	3.586	3.593	3.599	3.605	3.611	3.618	3.625	3.631	3.638	3.645	3.651	3.658	3.664	3.671	3.678	3.684	3.691	3.698	55
56	3.704	3.710	3.717	3.724	3.731	3.737	3.743	3.750	3.757	3.764	3.771	3.777	3.783	3.790	3.797	3.803	3.810	3.817	3.824	3.831	56
57	3.837	3.843	3.850	3.857	3.864	3.871	3.878	3.885	3.892	3.899	3.906	3.913	3.919	3.925	3.932	3.939	3.945	3.952	3.959	3.966	57
58	3.973	3.980	3.987	3.994	4.001	4.008	4.015	4.022	4.029	4.036	4.043	4.050	4.057	4.064	4.070	4.077	4.084	4.091	4.098	4.105	58
59	4.111	4.118	4.125	4.132	4.139	4.147	4.154	4.161	4.168	4.175	4.182	4.189	4.196	4.203	4.210	4.217	4.224	4.231	4.238	4.245	59
60	4.252	4.259	4.266	4.273	4.280	4.288	4.295	4.302	4.309	4.316	4.323	4.330	4.338	4.345	4.352	4.359	4.366	4.372	4.380	4.387	60
61	4.395	4.402	4.409	4.416	4.423	4.430	4.437	4.445	4.452	4.460	4.467	4.475	4.482	4.489	4.496	4.503	4.510	4.517	4.525	4.533	61
62	4.541	4.548	4.555	4.562	4.569	4.577	4.584	4.591	4.598	4.606	4.614	4.621	4.629	4.636	4.643	4.651	4.658	4.666	4.673	4.680	62
63	4.688	4.696	4.703	4.710	4.717	4.725	4.733	4.740	4.748	4.755	4.762	4.770	4.777	4.785	4.792	4.800	4.807	4.815	4.823	4.830	63
64	4.837	4.845	4.853	4.861	4.869	4.876	4.885	4.892	4.899	4.907	4.914	4.922	4.929	4.937	4.944	4.952	4.960	4.967	4.975	4.982	64
65	4.990	4.997	5.005	5.013	5.021	5.029	5.037	5.044	5.052	5.060	5.067	5.075	5.083	5.090	5.098	5.106	5.114	5.121	5.129	5.137	65
66	5.145	5.152	5.160	5.168	5.176	5.184	5.191	5.199	5.207	5.215	5.223	5.231	5.238	5.246	5.254	5.262	5.270	5.278	5.286	5.294	66
67	5.302	5.310	5.318	5.326	5.334	5.342	5.350	5.358	5.366	5.374	5.382	5.389	5.397	5.405	5.413	5.421	5.429	5.437	5.445	5.453	67
68	5.461	5.469	5.477	5.485	5.494	5.502	5.511	5.519	5.527	5.535	5.543	5.551	5.559	5.567	5.575	5.583	5.591	5.599	5.607	5.615	68
69	5.623	5.631	5.639	5.647	5.656	5.664	5.673	5.681	5.690	5.698	5.706	5.714	5.723	5.731	5.739	5.747	5.755	5.763	5.771	5.779	69
70	5.788	5.796	5.804	5.812	5.820	5.827	5.837	5.846	5.854	5.863	5.871	5.879	5.888	5.896	5.905	5.913	5.921	5.929	5.938	5.946	70
71	5.954	5.963	5.971	5.979	5.988	5.996	6.005	6.013	6.021	6.030	6.039	6.047	6.056	6.064	6.073	6.081	6.089	6.098	6.106	6.115	71
72	6.123	6.132	6.140	6.149	6.158	6.166	6.175	6.183	6.191	6.200	6.209	6.217	6.226	6.234	6.243	6.251	6.260	6.268	6.277	6.285	72
73	6.294	6.303	6.311	6.320	6.329	6.338	6.347	6.355	6.363	6.372	6.381	6.389	6.398	6.406	6.415	6.424	6.432	6.441	6.450	6.459	73
74	6.468	6.476	6.485	6.494	6.503	6.512	6.521	6.529	6.538	6.547	6.556	6.564	6.573	6.581	6.590	6.599	6.608	6.617	6.626	6.635	74
75	6.644	6.652	6.660	6.669	6.678	6.688	6.697	6.706	6.715	6.724	6.733	6.741	6.750	6.759	6.768	6.777	6.786	6.795	6.804	6.813	75
76	6.822	6.831	6.840	6.849	6.858	6.867	6.876	6.885	6.894	6.903	6.913	6.922	6.930	6.939	6.948	6.957	6.966	6.975	6.984	6.993	76
77	7.002	7.012	7.021	7.031	7.040	7.049	7.058	7.067	7.076	7.085	7.095	7.104	7.113	7.122	7.131	7.140	7.149	7.158	7.167	7.176	77
78	7.186	7.195	7.204	7.214	7.223	7.233	7.242	7.251	7.261	7.270	7.279	7.288	7.297	7.307	7.316	7.325	7.334	7.343	7.353	7.362	78
79	7.372	7.381	7.389	7.399	7.408	7.418	7.428	7.437	7.447	7.456	7.465	7.475	7.484	7.494	7.503	7.512	7.523	7.531	7.540	7.550	79
80	7.559	7.568	7.578	7.587	7.596	7.606	7.615	7.625	7.634	7.644	7.654	7.663	7.673	7.683	7.692	7.702	7.711	7.721	7.730	7.740	80
81	7.750	7.759	7.768	7.777	7.787	7.796	7.806	7.816	7.826	7.836	7.846	7.855	7.864	7.870	7.884	7.894	7.904	7.913	7.922	7.932	81
82	7.942	7.952	7.961	7.971	7.980	7.990	7.999	8.009	8.019	8.029	8.039	8.049	8.059	8.069	8.078	8.088	8.098	8.108	8.117	8.127	82
83	8.137	8.147	8.156	8.166	8.176	8.186	8.196	8.206	8.216	8.226	8.236	8.246	8.256	8.266	8.275	8.285	8.295	8.305	8.315	8.325	83
84	8.334	8.344	8.354	8.364	8.374	8.384	8.394	8.404	8.414	8.424	8.434	8.444	8.454	8.464	8.474	8.484	8.494	8.504	8.514	8.524	84
85	8.534	8.544	8.554	8.564	8.574	8.584	8.594	8.604	8.614	8.624	8.635	8.645	8.655	8.665	8.675	8.685	8.695	8.705	8.715	8.725	85
86	8.736	8.746	8.756	8.766	8.776	8.786	8.796	8.806	8.817	8.827	8.837	8.848	8.858	8.868	8.877	8.887	8.899	8.909	8.919	8.929	86
87	8.940	8.950	8.960	8.970	8.981	8.991	9.001	9.011	9.021	9.032	9.043	9.053	9.064	9.074	9.085	9.095	9.105	9.116	9.126	9.137	87
88	9.147	9.157	9.167	9.178	9.188	9.195	9.209	9.220	9.230	9.241	9.251	9.261	9.272	9.282	9.293	9.304	9.314	9.325	9.335	9.346	88
89	9.356	9.367	9.377	9.388	9.398	9.409	9.419	9.430	9.441	9.451	9.461	9.471	9.483	9.493	9.504	9.514	9.525	9.536	9.545	9.557	89
90	9.568	9.579	9.589	9.600	9.610	9.621	9.631	9.642	9.653	9.663	9.674	9.684	9.695	9.706	9.717	9.728	9.738	9.747	9.759	9.770	90
91	9.781	9.792	9.802	9.813	9.824	9.835	9.846	9.856	9.867	9.878	9.889	9.899	9.910	9.921	9.932	9.943	9.953	9.964	9.975	9.986	91
92	9.997	10.008	10.018	10.029	10.040	10.051	10.062	10.073	10.084	10.095	10.106	10.117	10.128	10.139	10.150	10.161	10.172	10.183	10.194	10.205	92
93	10.216	10.227	10.238	10.249	10.260	10.271	10.282	10.293	10.304	10.315	10.326	10.337	10.348	10.359	10.370	10.381	10.392	10.403	10.415	10.426	93
94	10.437	10.447	10.460	10.471	10.482	10.493	10.504	10.515	10.526	10.537	10.548	10.560	10.571	10.582	10.593	10.604	10.616	10.627	10.638	10.649	94
95	10.660	10.672	10.683	10.694	10.705	10.716	10.728	10.739	10.750	10.762	10.773	10.784	10.795	10.806	10.817	10.829	10.840	10.852	10.863	10.874	95
96	10.885	10.896	10.908	10.919	10.930	10.942	10.954	10.965	10.977	10.988	10.999	11.011	11.022	11.034	11.045	11.056	11.068	11.079	11.090	11.102	96
97	11.113	11.124	11.136	11.147	11.159	11.170	11.182	11.194	11.205	11.217	11.228	11.240	11.251	11.263	11.274	11.286	11.297	11.309	11.320	11.332	97
98	11.344	11.356	11.367	11.378	11.390	11.402	11.413	11.425	11.436	11.448	11.460	11.471	11.483	11.494	11.506	11.518	11.529	11.541	11.552	11.564	98
99	11.576	11.587	11.599	11.611	11.623	11.635	11.647	11.658	11.670	11.682	11.694	11.706	11.717	11.729	11.740	11.752	11.763	11.775	11.787	11.799	99

42 gallons equal 1 barrel.

FOR TANKS MORE THAN 100 FT. CIRCUMFERENCE, DIVIDE THE CIR. BY 2, AND TAKE OUT OF TABLE THE AMOUNT OPPOSITE THE QUOTIENT, MULTIPLY THIS AMOUNT BY 4 FOR BBLS PER INCH.

Temple Oil Company Tank No. 282, Crow Lease, Jennings Field. June 19, 1920

Height Above Bottom	Circumference in Feet	Difference in Circumference
[illegible]'—6"	88.08	1.13
2'—6"	86.95	1.13
4'—6"	85.94	1.01
6'—6"	84.83	1.11
8'—6"	83.59	1.24
10'—6"	82.36	1.23
12'—6"	80.88	1.48
14'—6"	79.53	1.35
	672.16	

Thickness of stave, 2 inches. Height, 15 feet 6 inches.
Deadwood · 23 pieces 2x6 uprights. Eighty feet 1x6 braces at 8 to 9 feet from bottom of tank.

The volume of the tank is computed in barrels per inch in the different zones, the volume calculations usually being made every 3 inches. The calculations are made as for frustrums of cones. The volumes are computed for depths of ¼ inch. The following is an example of the computation for the volume for a ¼-inch frustrum in the zone between 6 feet 6 inches and 7 feet 6 inches:

Circumference at 6 feet 6 inches	84.83
Circumference at 7 feet 6 inches	84.52
Mean circumference	84.52
Deduction for 2-inch stave	1.04
Inside mean circumference	83.48

$$\text{Barrels per } \tfrac{1}{4} \text{ inch} = \frac{(83.48)^2 \times .0011811}{4} = 2.0548$$

$$\text{Deadwood deductions} = \frac{23 \times 2 \times 6}{4 \times 231 \times 42} = .0071$$

Net barrels per ¼ inch	2.0477

The regular deduction per cent for loss in storage will be deducted from 2.0477. The contents in barrels per ¼ inch are calculated for the regular intervals, the intervening capacities per ¼ inch obtained by interpolating and the whole added up on an adding machine After each addition, a sub-total is struck off on the machine and this sub-total gives the total contents of the tank in barrels to that point. It is the sub-totals which are used in making up the actual tank table which is used in gaging. The tank table gives the number of barrels in the tank at any depth. A total of 744 sub-totals

would be needed in making a table with readings every ¼ inch where a tank is 15 feet 6 inches deep.

Steel tanks—In strapping 55,000-barrel steel storage tanks containing crude oil of fuel oil grade it is customary to take but one circumference measurement at the top of the first course of steel plates. Different companies have different rules in regard to this, however. Some companies take two circumference measurements, one being around the middle of the second ring and one around the middle of the top ring. Still other companies take measurements around the top of every ring, possibly interpolating for the measurements on the fourth and fifth rings. This procedure is rather unnecessary, however, as in measurements taken so far above the ground inaccuracies are apt to creep in which will more than offset any difference which might exist in actual circumference. The circumference of the top course is taken by reaching down over the eaves of the tank, the tapemen lying flat on the roof. The height of the tank is considered to be the distance between the base of the bottom angle iron of the tank and the top of the top angle iron.

The deadwood in the tank must be measured carefully and the vertical position of each timber given. In giving timbers such as mud sills, the flat side is usually given first; i.e. if sills are 2 by 12 inches and 6 feet long with the 12-inch side lying flat they should be given as 12 by 2-inch by 6 feet. Total volume of diagonals is figured and divided proportionally for the vertical distance through which they extend.

The tank table prepared must give the total number of barrels for each inch of depth and at one side a small table of capacities for sixteenths of an inch. This latter table is gotten by taking the reading that is used most in making up the table and dividing it into barrels per sixteenth of an inch.

Example of 55,000-Barrel Tank Strapping and Preparation of Tank Table

Field notes.—Yupon Petroleum Company. Tank No. 876. Hare Tank Farm, Pine Island District. Strapped April 26, 1917, by T. R. B. for Yupon Petroleum Company and J. C. Case for Pelican Pipe Line Company.

Total outside circumference, 360.23 feet. Height, 30.29 feet, 30 feet 3½ inches. Plate thickness, 7/16.

Deadwood:

0'0"— 0'3" 308'—10"×3" sills.
0'3"— 0'9" 119'— 8"×6" blocks.
0'9"—19'0" Forty 6×8 posts; Thirty-one 6×6 posts.

19'0"—20'0" Forty 6×8 posts; Thirty-one 6×6 posts.
1155 feet 2×6 braces.
20'0"—29'8" Forty 6×8 posts Thirty-one 6×6 posts.
480 feet 1×6 diagonals.
29'8"—29'10" Twenty 6×8 posts; Thirty-one 6×6 posts; Twenty 8×2×1' Caps.
29'10"—30'3" Twenty 6×8 posts; Thirty-one 6×6 posts; 340 feet 6×6 eaps.

Office Work:

360.23 Outside circumference
0.23 Deduction for plate

360.00
360

2160
1080

12960.00 = C^2

$C^2 \times .0011811 = 12960.00 \times .011811$
$= 153.07056$ = Gross barrels per inch depth
Deducting 2% $= 153.07 - 3.06$
$= 150.01.$

Deadwood Calculations:

0'0"—0'3":

$$\frac{308\times12\times10\times1}{42\times231} = \frac{6160}{1617} = 3.809$$ bbls. per inch taken up by deadwood

150.01—3.809 = 146.20 Net bbls. per inch at this depth.

0'3"—0'9":

$$\frac{119\times12\times8}{42\times231} = \frac{1904}{1617} = 1.177$$

150.01—1.177 = 148.83 Net bbls. per inch depth.

0'9"—19'0":

$$\frac{(40\times6\times8) + (31\times6\times6)}{42\times231} = .31$$

150.01—.31 = 149.70 Net bbls. per inch depth.

19'0"—20'0":

$$\frac{40\times6\times8}{42\times231} + \frac{31\times6\times6}{42\times231} + \frac{1155\times12\times2\times6}{12\times42\times231} = 1.74$$

150.01—1.74 = 148.27 Net bbls. per inch.

20'0"—29'8":

$$\frac{40\times6\times8}{42\times231}+\frac{31\times6\times6}{42\times231}+\frac{480\times12\times1\times6}{116\times42\times231}=0.34$$

150.01—.34 = 149.67 Net bbls. per inch.

29'8"—29'10":

$$\frac{(20\times6\times8)+(31\times6\times6)+(20\times12\times8)}{42\times231}=0.41$$

150.01—0.41 = 140.60 Net bbls. per inch.

29'10" to top:

$$\frac{(20\times6\times8)+(31\times6\times6)+(340\times12\times6)}{42\times231}=2.74$$

150.01—2.74 = 147.27

The figure 149.70 is divided into sixteenths and used in making up the table for sixteenths.

In making up the tank table the adding machine is used the same as for tank tables for cypress tanks, sub-totals being drawn after each addition. In this particular case 146.20 would be added three times, then 148.83 would be added to this six times and 149.70 would be added to this 219 times and so on until each increment was added the proper number of times for the depth through which it occurs. The grand total is the net capacity of the tank.

In preparing tank tables for tanks in which heavy Mexican Crude (12 degrees Baume) is stored "outage" tables are generally used. These tables give the capacity of the tank according to the measurement to the top of the fluid from a fixed point on top of the tank. This is done because of the difficulty of getting the plumb bob on a steel gaging tape through the heavy fluid and the trouble of locating "bottom" accurately. A long brass bar, carefully marked to eights of an inch is lowered on the end of the gaging tape a couple of inches into the fluid and a careful reading taken on the "knife blade" on top of the tank. The gaging tape is then pulled out and the reading on the brass bar deducted. The net reading is the correct "outage" in the tank and the tank table shows the amount of oil in the tank for this outage.

Preparing Tank Tables for Large Earthen and Concrete Storage Tanks[1]

Reservoir Measurements and Tables.—For the convenience of the gager a small hatch is placed in the roof of the tank, usually near the head of the stairway. The gage tape is suspended through the hatch into the open tank. However, as regards reservoirs, it is customary to set what is known as a gage plate at some convenient place as close as practicable to the lowest point in the bottom of the reservoir and to take all measurements for depth of oil from this plate. It comprises a steel plate about ½ inch in thickness and 3 feet square, which is set with foundation bolts and carefully leveled and grouted. This work is done as the part of the floor in that vicinity is being constructed so that it becomes an integral part of the lining. Some companies use a smaller gage plate and place on it a vertical pipe 4 to 10 inches in diameter of sufficient length to extend out through the roof of the reservoir. The walls of the pipe are perforated or slotted, and the top is fitted with a cap. Measurements for depth of oil are then taken through the pipe.

Testing Gage Plates.—One of the first duties of the field or construction engineer in the procuring of data necessary for the preparation of a gage table for the reservoir is to examine carefully the gage plate and determine whether all the foundation bolts are tight, and whether the plate has been properly grouted and has not sprung at any point, but is absolutely level over its entire surface. The following information should then be procured:

Necessary Measurements in Testing Gage Plates

1. The diameter at the toe of the inner slope[2].
2. The diameter at the top of the inner slope[2].
3. The elevation of the gage plate.
4. The elevation of a sufficient number of points on the bottom so that an accurate contour map may be plotted, the contour interval of which should not be more than one-fourth of an nich.
5. The dimensions of all footings, posts, braces, and other deadwood as outlined for tank strappings[3].

[1]Bulletin No. 155, Bureau of Mines.
[2]This measurement should be taken in as many places as possible and carefully checked.
[3]As regards a reservoir, however, on account of the slope of the bottom, the exact location of the deadwood must also be determined.

6. The location and the size of the pump containing the swing pipes and the water draw-off pipes.

Computing Gage Table.—From the elevation of the points on the bottom of the reservoir a contour map of one-fourth inch material interval is plotted and from this the gross content up to the gage plate is computed. To this is added the volume of the sump and from the sum is subtracted the volume of the deadwood up to the plane of the gage plate. The net amount thus obtained gives the content of the reservoir up to 0 feet 0 inches on the gage table.

If the gage table is to read to one-eights of an inch, as is usually the case, the content is computed in a similar manner proceeding by eighths of an inch, up to the point where a horizontal plane will cut the side slopes of he reservoir. From this point to the top the volume is computed at one-eighth inch intervals, the reservoir being considered as a frustrum of a cone, deadwood being deducted as in the tank-table computations.

Gage tables are made to read to the nearest one-hundredth of a barrel. Volumes for fraction of an inch less than one-eighth are obtained by interpolation.

CONTRACT SPECIFICATIONS FOR 55,000-BARREL STEEL TANK WITH STEEL ROOF[1]

The ————, in itself or by its duly authorized representative, shall be referred to in these specifications as the "Company."

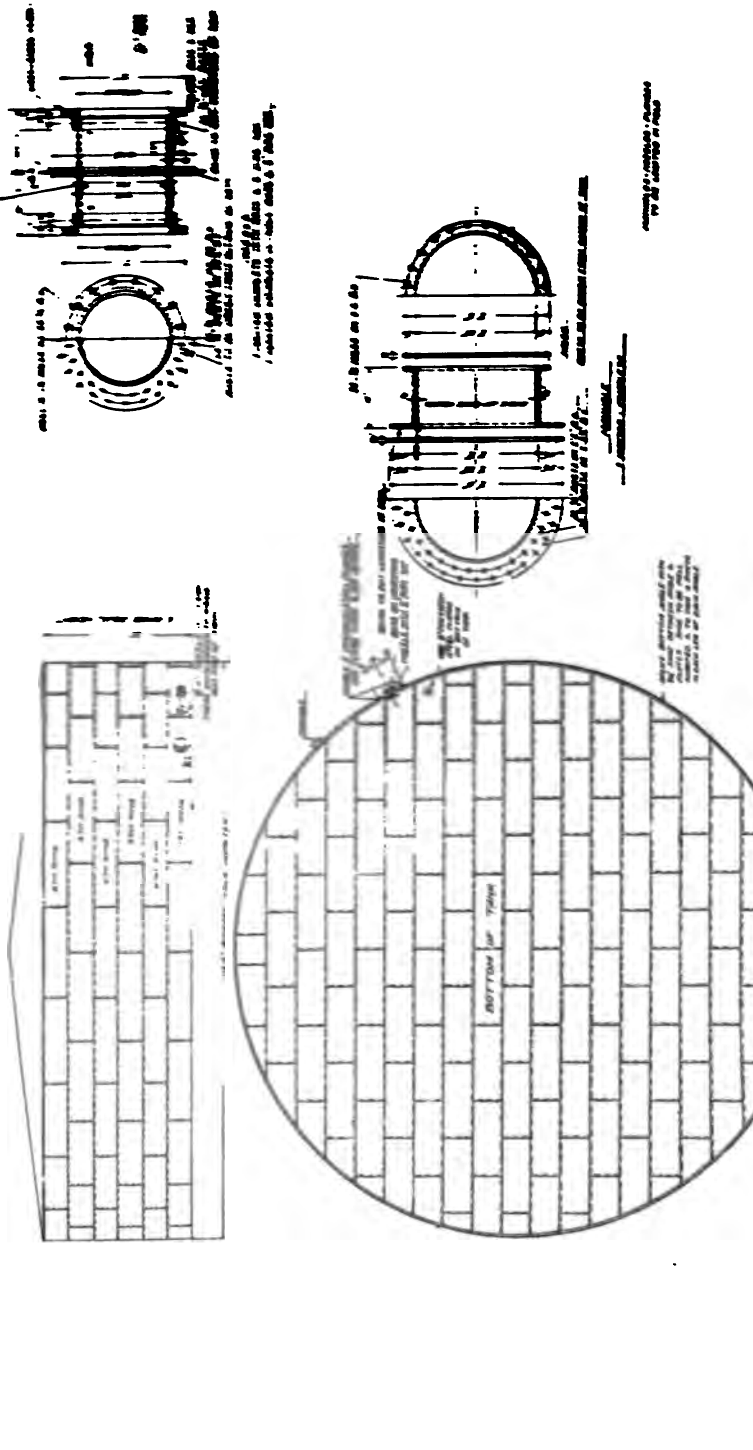
The firm undertaking to furnish and erect this tank herein described, in itself or by its duly authorized representative, shall be referred to in these specifications as the "Contractor."

At all times during the progress of the fabrication of the tank material or erection of the tank, the Contractor shall designate some person as his representative, to whom instructions may be given by a duly authorized representative of the company.

Location.—Tank to be erected upon foundation prepared by the company.

Freight and hauling.—The Contractor shall deliver all tank material, tools, and appliances f. o. b. cars nearest railroad station. The company shall haul all tank material, tools, and appliances neces-

[1]United States Bureau of Mines. Bulletin No. 155.



DETAILS OF A 55,000-BARREL 8-RING STEEL TANK.

Fig. 154

sary for the construction of the tank from the railroad station, and shall deliver same within 100 feet of the tank site, and on completion of the work shall return tools and appliances to the railroad station.

Drawings.—The following drawings form an integral part of and are to be used in conjunction with these specifications: Figures 154 to 160.

Dimensions.—Diameter, 114 feet 6 inches, average inside measurement; height, 30 feet.

Material.—All material for the tank shall be of steel, complying with Standard Specifications for Structural Steel of the American Society for Testing Materials (copy of which is hereto attached). Contractor to furnish a certificate from an approved firm of testing engineers covering all materials used, but such certificate shall not act to prevent company exercising the right to reject undergaged plates or defective material wherever it may be found.

Tank to be composed of 6 rings of equal height, as shown in Fig. 154. Plates to be of uniform size with minimum dimensions, as hereinafter designated.

All plates shall be ordered to gage, permissible variations to be in accord with specifications above referred to.

Punching and riveting, etc.—Plates and angles for the shell of the tank must be rolled to proper curvature.

Plates and angles must be punched from the sides that are to be in contact, and the punching must be so accurate that the holes will match within 10 per cent of their diameter when plates are assembled. Holes for hot rivets shall be punched not more than one-sixteenth of an inch larger in diameter than the rivets that are to fill them.

Riveting shall be done with pneumatic tools, and air pressure of approximately 90 pounds per square inch at the receiver being used. Rivets must conform with the specifications in diameter, length, pitch, and marginal distance. Should any burned, deformed or loose rivets be found in the work, they are to be cut out and replaced. No calking of the rivets will be allowed. Riveting of the bottom sheets shall be done from the inside; all other riveting including riveting of the bottom to the bottom angle, and of the roof, shall be done from the outside. All rivets one-half inch in diameter or larger shall be driven hot.

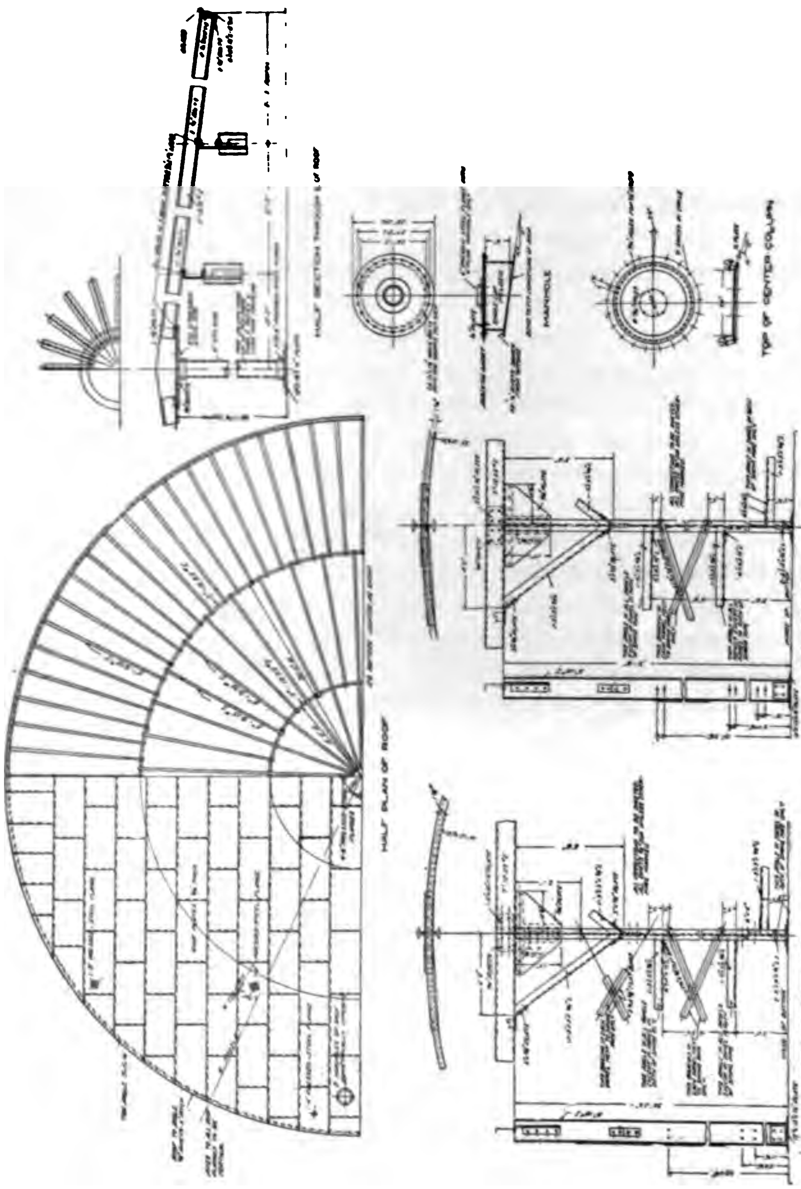

HALF PLAN OF ROOF
HALF SECTION THROUGH ℄ OF ROOF
MANHOLE
TOP OF CENTER COLUMN
OUTER COLUMN

Fig. 155

Calking.—All edges to be calked shall be beveled by planing. All seams must be thoroughly calked with a round-nosed pneumatic calking tool. The shell of the tank shall be formed by ascending inside courses calked on the outside. Bottom plates to be calked on the inside except on the angle iron, where they are to be calked on the outside, and both legs of angle iron shall be calked inside. Angle irons to be butt calked at joints.

All roof plates to be calked from the outside of tank, this to include also calking at top angle iron.

All castings, nozzles, flanges and manheads riveted to the tank must be calked thoroughly inside and outside.

Testing the bottom.—Upon completion of the bottom and the first ring of the shell, and before the bottom has been lowered to the ground, the bottom shall be covered with water to a depth of not less than 5 inches, and all leaks that develop shall be made tight to the satisfaction of the company or its duly authorized representative before any lowering is done. Necessary water for the testing shall be furnished by the company for one test only. Should additional tests be made, water will be charged to the contractor at cost.

Thickness of metal, spacing of rivets, etc.—The thickness of metal, the spacing of rivets, and the like, shall be set forth in the following table.

Thickness of Metal, Spacing of Rivets, etc., Prescribed for Tank Covered By These Specifications

Part	Thickness.	Weight per square foot.	Horizontal riveting—all single rows. Diameter of rivets.	Pitch.	Vertical riveting. Rows.	Diameter of rivets.	Pitch.	Distance between rows, center to center.
	Ins.	Lbs.	In.	Ins.		In.	Ins.	Ins.
Bottom sketch plates	5/16	12.75	½	1½				
Bottom rectangular plates	1/4	10.20	½	1½				
First ring	9/16	22.95	1	2½	Triple	¾	3	2
Second ring	1/2	20.40	⅞	2½	Triple	¾	3	2
Third ring	13/32	16.58	¾	2½	Double	¾	2½	2
Fourth ring	5/16	12.75	¾	2½	Double	⅝	2¼	1¾
Fifth ring	1/4	10.20	⅝	2	Double	⅝	2¼	1¾
Sixth ring	1/4	10.20	⅝	2	Double	⅝	2¼	1¾
Roof plates	3/16	7.65	⅜	1¼				

Size of plates and angles.—Plates for shell shall be 60 by 180 inches center to center of rivet laps (24 plates per ring). Bottom and top rectangular plates shall be 60 by 180 inches center to center of rivet laps. Bottom angle irons connecting the shell shall be 4 by 4

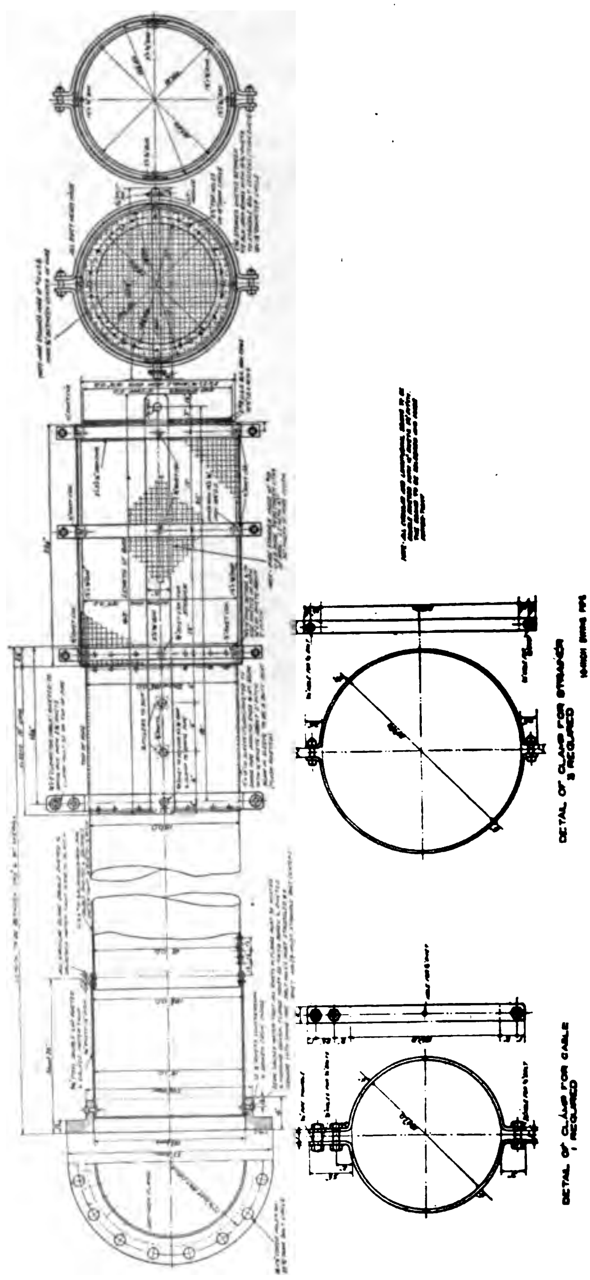

DETAIL OF CLAMP FOR STRAINER
3 REQUIRED
DETAIL OF CLAMP FOR CABLE
1 REQUIRED

Fig. 156

inches by 5/8 inch. Top angle irons connecting the roof with the shell shall be 3 by 3 inches by 3/8 inch.

Angle shoes.—Shoes uniting ends of angles shall be made of 3/8-inch, 16-pound steel, and shall be not less than 12 inches in length with the ends drawn to a thin edge. Shoes must be set between steel angles, shell and bottom of tank, and must be of sufficient width to be properly calked outside the line of the steel angles.

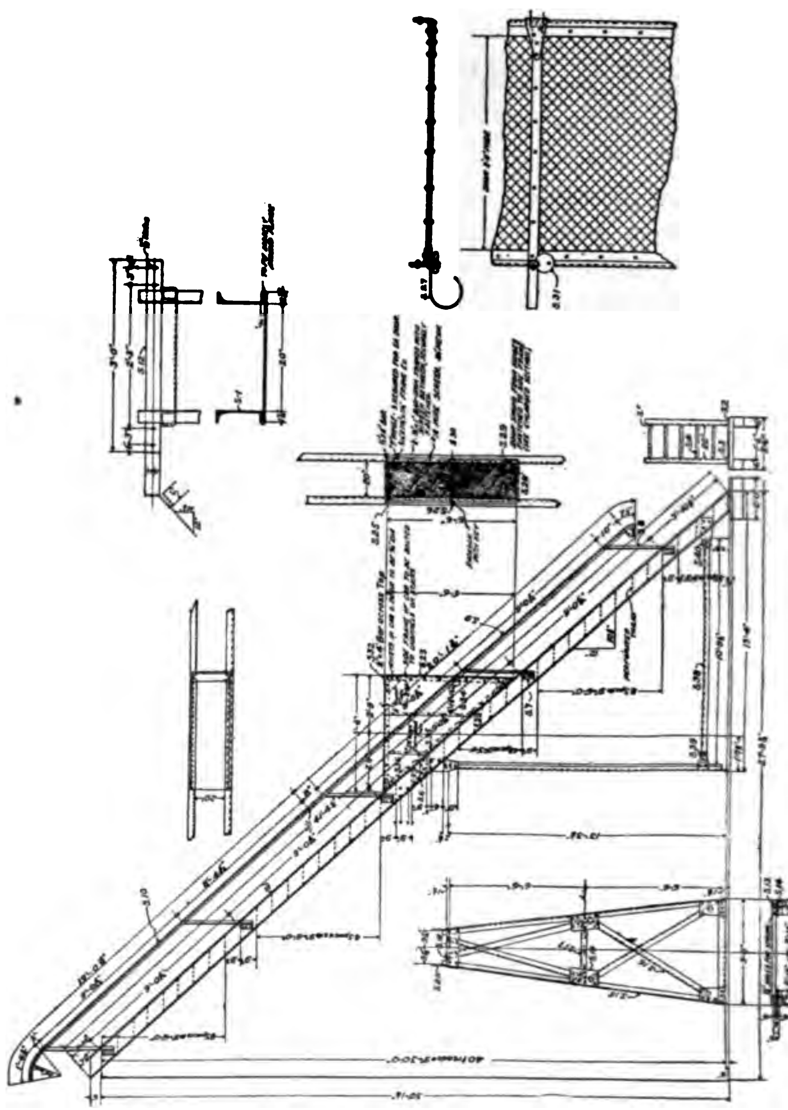
Shell.—The shell shall be composed of 6 courses, as shown on Fig. 154, each course to be a true circle and to be free from flaws and buckles. The first two courses, counting from the bottom upward, are to have the vertical seams triple riveted. The third, fourth and fifth courses are to have the seams double riveted. All horizontal seams are to be single riveted.

Roof.—Roof to be composed of 3/16-inch steel plates, weighing 7.65 pounds per square foot, and to rest on steel roof supports as shown in Fig. 155. The roof, however, shall not be riveted to roof supports at any point. When complete the roof must be "gas tight," and shall show no leaks when tested with an air pressure equal to the weight of the roof.

Roof supports.—Roof supports shall be constructed of steel shapes as shown on Fig. 155. Size and fabrication shall conform to those shown, and workmanship to be approved by the company.

Manholes.—Two manholes shall be placed in the first course of tank, as designated by the company in the field. Each manhole shall be 20 inches deep, and shall be made of steel with welded seam, weighing not less than 21 pounds per square foot. Neck of flange must be covered to suit radius of tank shell. The manhole shall be fitted with steel cover plate 5/8 inches thick, faced and punched to suit holes in flange, and bolted to flange with 24 3/4-inch square-head bolts and hexagon nuts. The manhole shall be riveted to tank shell with 3/4-inch rivets, as shown on Fig. 154.

Pipe flanges, nozzles, etc.—The tank shall be furnished with the following pressed-steel flanges secured to the shell with 3/4-inch diameter rivets. Position to be designated in field by the company. One pair of flanges to be threaded for 8-inch pipe for drawing off water. One pair of flanges to be threaded for 8-inch pipe for oil inlet pipe. Bottom of tank to be fitted with one single flange



STANDARD STEEL STAIRS FOR [illegible]-FOOT TANK.

Fig. 158

threaded for 8-inch pipe, secured to bottom of tank with ½-inch rivets, location to be designated in the field by the company, also with manhole and gage hatch, as shown in detail on Fig. 155.

Tank to be fitted with one combined swing pipe and suction nozzle, as shown in detail on Fig. 154. Nozzle to be made of single-lap forge-welded steel plate ½-inch thick, and to be secured to shell of tank in position located in the field by the company, with a double row of ¾-inch rivets, as shown on drawing. Swing pipe and suction end of nozzle to be fitted with cast steel flange, as shown.

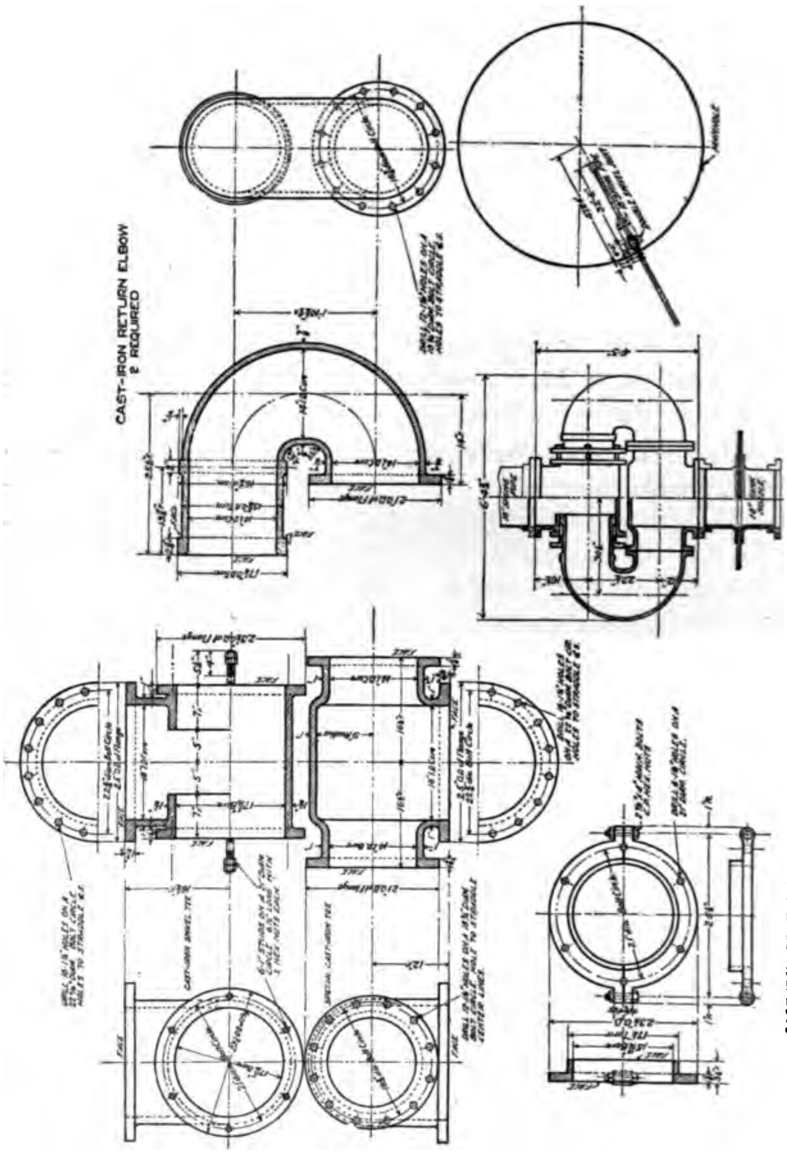
Swing pipe.—Contractor shall supply and install swing pipe as shown in detail on Fig. 156. Swing pipe to be delivered on the job so that it may be placed (but not installed) inside of the tank shell as soon as the bottom is tested and lowered. Contractor will not be permitted to lift the swing pipe over the shell of the tank after the first ring of the tank is in position.

Double-swivel joint for swing pipe.—Contractor shall supply and install to the satisfaction of the company a double-swivel elbow joint for connecting the swing pipe to the swing pipe nozzle. Details for this swivel joint are shown on Fig. 157. Construction of joint must follow closely details as per drawing.

Stairway.—The Contractor shall furnish and install a stairway anchored to the shell of the tank and running from the ground to the top of the tank, as shown on Fig. 158. This stairway shall be equipped with door covered with No. 12 wire screen, ¾-inch mesh, as shown on Fig. 158.

Explosion hatches.—The tank shall be equipped with eight explosion hatches to be located on the roof of the tank in the field as designated by the company. Details of the explosion hatches are shown on Fig. 159. These explosion hatches must be furnished by the contractor and must conform closely to the drawing. Brass rods must be true and smoothly turned, and must be accurately fitted in babbited bearings, as shown, in order that aluminum cover of hatch will rise without binding.

Cable guides and stuffing box.—Tank shall be provided with cable guide and stuffing box for cable, as shown in detail on Fig. 160. One hundred feet of ½-inch diameter 6-strand 19-wire plow-steel galvanized wire cable shall be furnished by contractor. Sheave wheels for cable must be accurately centered and supports



GENERAL ARRANGEMENT.
DOUBLE-SWIVEL JOINT FOR 18-INCH SWING PIPE.
Fig. 157

securely riveted to tank shell and calked inside and outside of tank.

Swing-pipe winch.—Swing-pipe winch shall be furnished by contractor as per detail shown on Fig. 160, and shall be placed in position by contractor where designated by company.

Painting.—The outside of the tank, including the top, shall be painted with one coat of asphaltic, graphite, or other paint approved by the company, to be spread on with brush and to thoroughly cover the metal. The bottom of the tank shall be painted with three coats of the same paint outside and inside; at least six hours shall be allowed for each successive coat to dry.

Inspection.—All material and workmanship shall be subject at all times to the inspection of the company or its duly authorized representative, and any defective material, whether discovered before or after it has been used in the work, shall be replaced by the contractor at his own expense. Contractor shall also furnish transportation from the railroad to the tank site for such new material.

Final test.—Upon the completion of the tank, and before it is inspected, it may be filled with oil or water at the option and expense of the company, and any leaks that develop shall be made tight to the satisfaction of the company by the contractor at his own expense.

Boarding of work crew.—The contractor shall provide board, lodging and transportation for his men at all times. Commissary water will be furnished by the company. Purifying of same, where necessary, to be done by the contractor. No intoxicating liquors shall be permitted on the premises.

Workmanship.—The work throughout shall be done in a first-class workmanlike manner, and only men competent in their line shall be employed on the work. Upon demand of the company, or its duly authorized representative, any workman who in the judgment of the company is found to be incompetent, careless, or intemperate, shall be dismissed.

Extra work.—These plans and specifications are intended to describe a complete oil-tight and gas-tight tank. Any work and material necessary to produce such a tank, although not mentioned in the specifications or shown on the plans, shall be supplied by the contractor without extra cost to the company. The company will not pay for extra work unless it has been executed on a written order by the company, or its duly authorized representative.

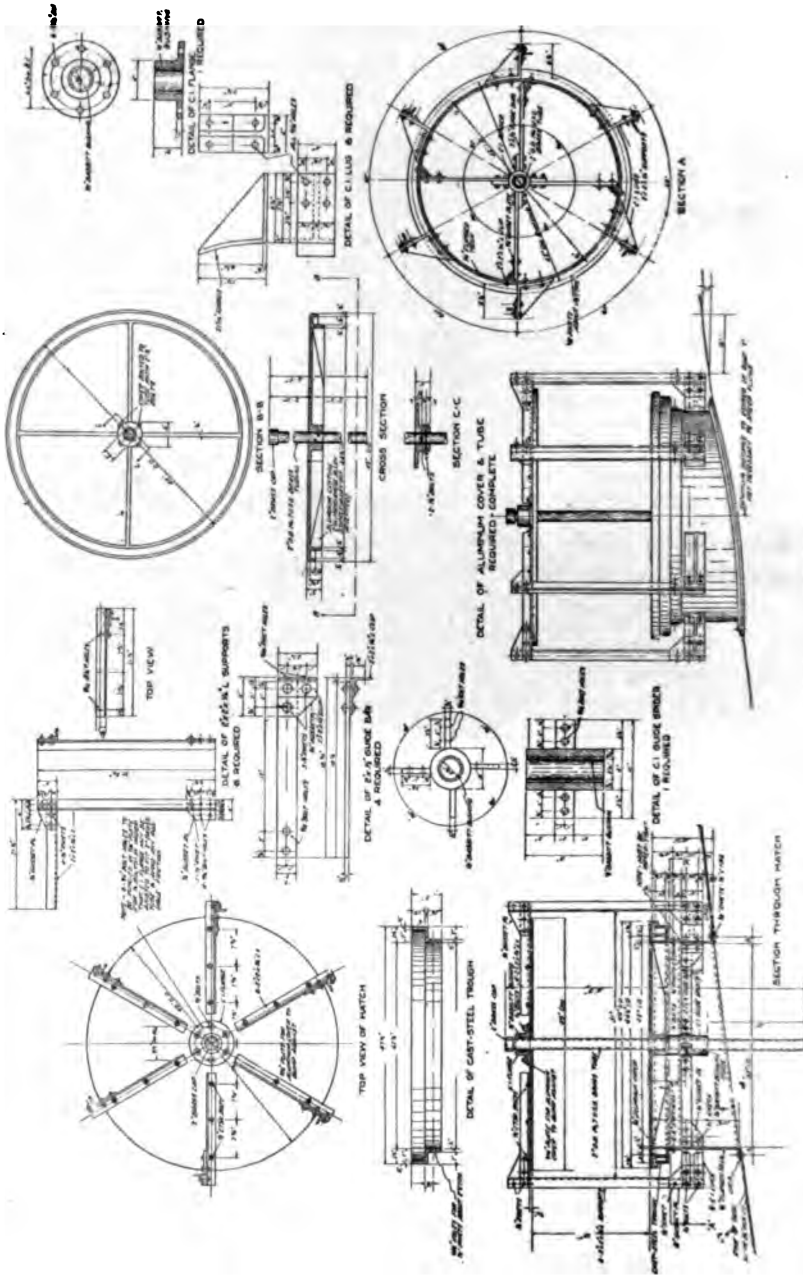
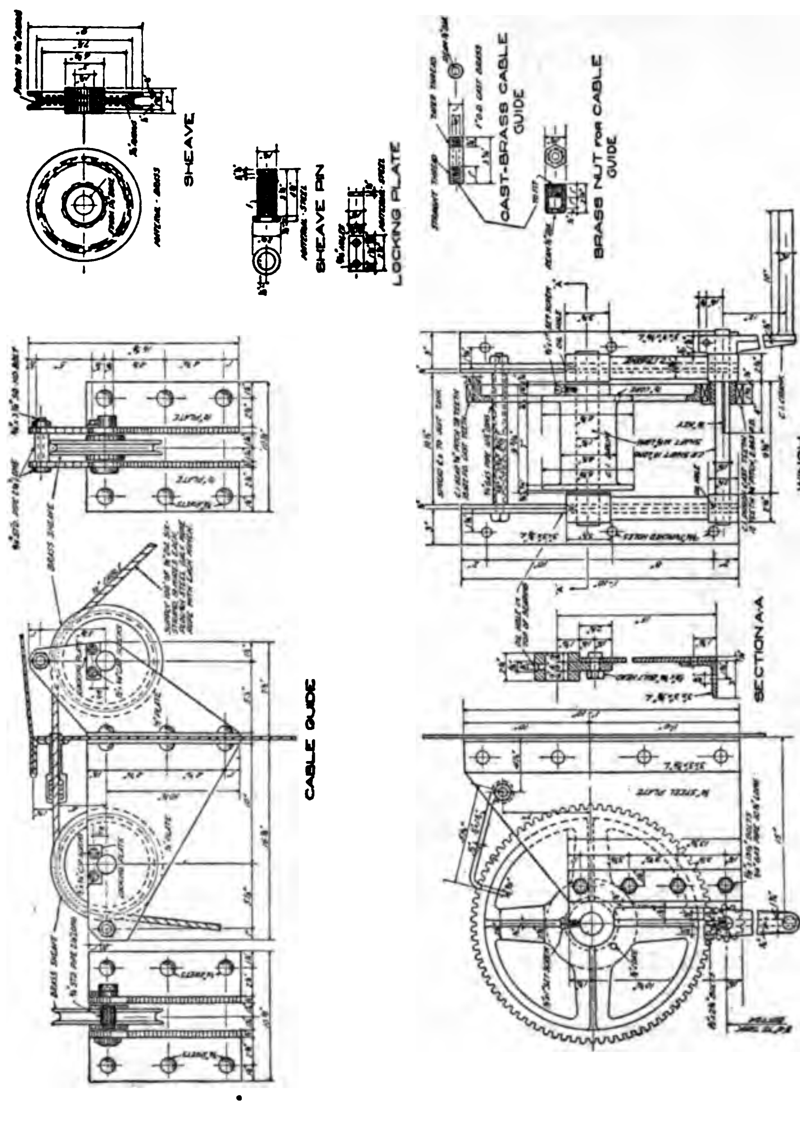

SECTION A
DETAIL OF C.I. LUG 6 REQUIRED
TOP VIEW
SECTION B-B
CROSS SECTION
SECTION C-C
DETAIL OF ALUMINUM COVER & TUBE REQUIRED-COMPLETE
DETAIL OF C.I. GUIDE GIRDER 1 REQUIRED
TOP VIEW OF HATCH
DETAIL OF CAST-STEEL TROUGH
SECTION THROUGH HATCH

Fig. 159



GEARED WINCH AND CABLE GUIDE FOR SWING-PIPE CABLE
Fig. 160

Rubbish.—On completion of the work all useless material used in the construction shall be cleared away from inside and outside the tank, and shall be removed to such a point on the premises as may be designated by the company.

Camp sanitation.—The contractor shall at all times maintain his boarding house, sleeping quarters, and all other appurtenant facilities in a sanitary condition to the satisfaction of the company.

Tanks with Wooden Roofs[1]

Many companies, especially those handling heavy oils, are still constructing tanks with wooden roofs. The roofs are composed of sheathing 1 by 6 inches or 1 by 12 inches, generally sized, but sometimes laid on in the rough, on rafters 2 by 8 inches, supported by girders 5 by 12 inches or 6 by 12 inches, resting on posts 6 by 6 inches. Footing blocks 2 by 8 inches and about 3 feet long are usually provided for the posts. The tops of the posts where girders join are also provided with corbels of the same size and material as the footing blocks. The posts are tied together in each successive ring by sway braces of material 1 by 6 inches, placed diagonally.

Some builders also tie the rings of posts together at various points. This practice, however, is not general and is of questionable benefit as regards strengthening the structure.

The sheathing boards are usually covered with a good grade of roofing paper which is essentially a deadening felt rendered waterproof by having been immersed in a hot solution of asphaltic material, and then rolled under heat and pressure. Roof coverings are also built up with layers of building paper or burlap coated and stuck together with asphaltum, and having a pebble finish on top. Such coverings should not be applied to a newly constructed roof before it has had time to season thoroughly, as the lumber in seasoning will almost surely tear the covering apart in some places and badly pucker it in others.

Sheet iron is also used for a covering for wooden roofs. The writer has seen some such roofs so well constructed that to all appearances they do not leak water and are reasonably tight even to the passage of gases. This construction has the disadvantage that the nails used for fastening on the iron will soon become loose

[1]U. S. Bureau of Mines. Bulletin No. 155.

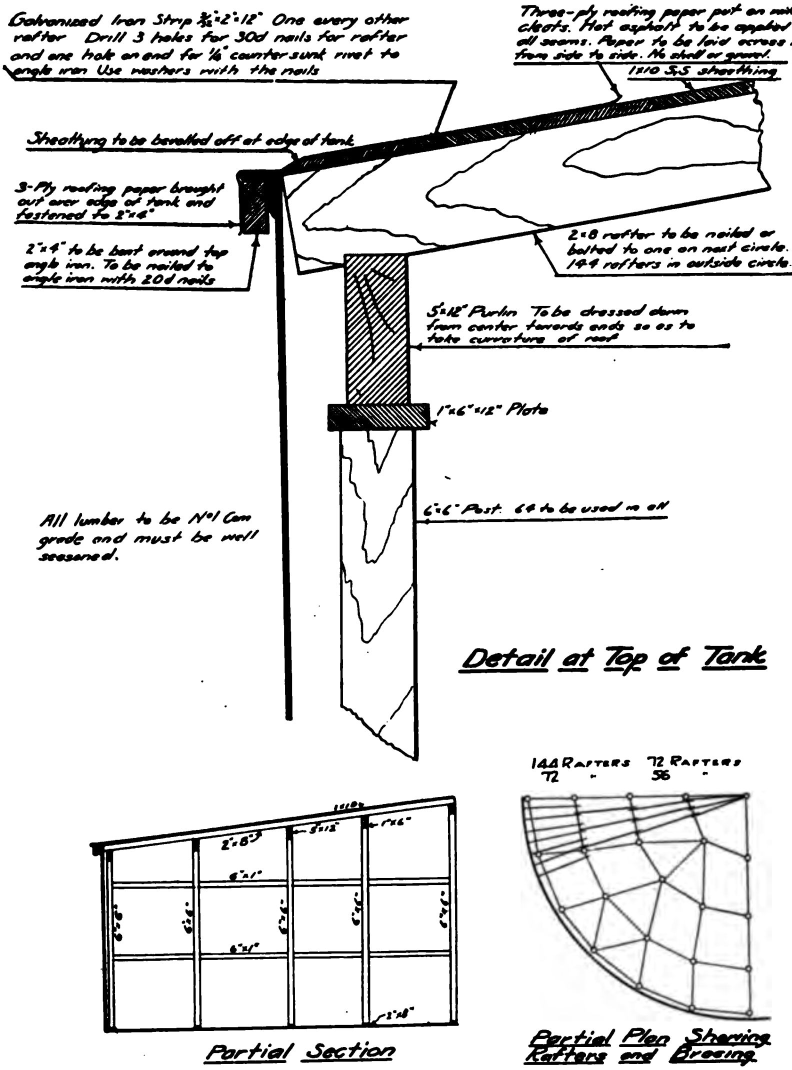


Fig. 160A—Standard windproof wooden roof for 55,000 barrel tank

in the sheathing on account of the wood having shrunk or become brash. There is a danger therefore that the wind during a storm may get a foothold under a sheet so loosened and tear a considerable part of iron from the sheathing. This same objection holds true with a paper-covered roof. Once the covering of a wooden roof

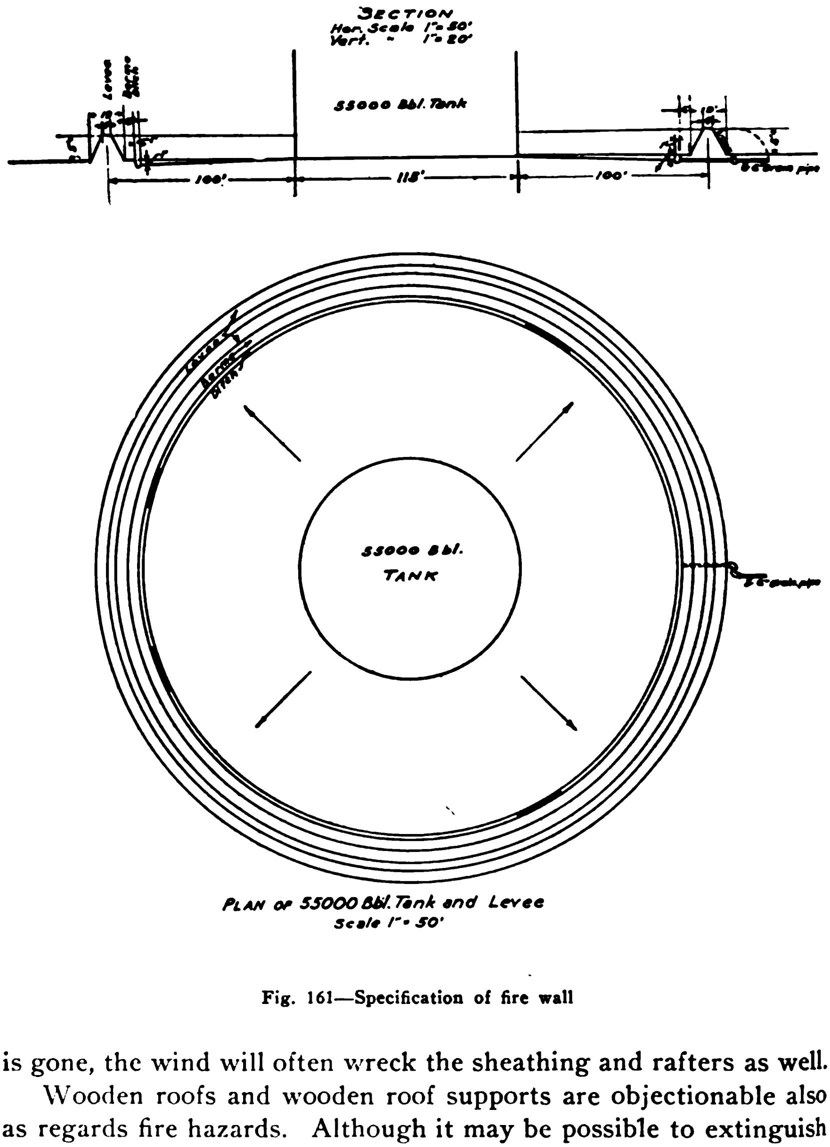
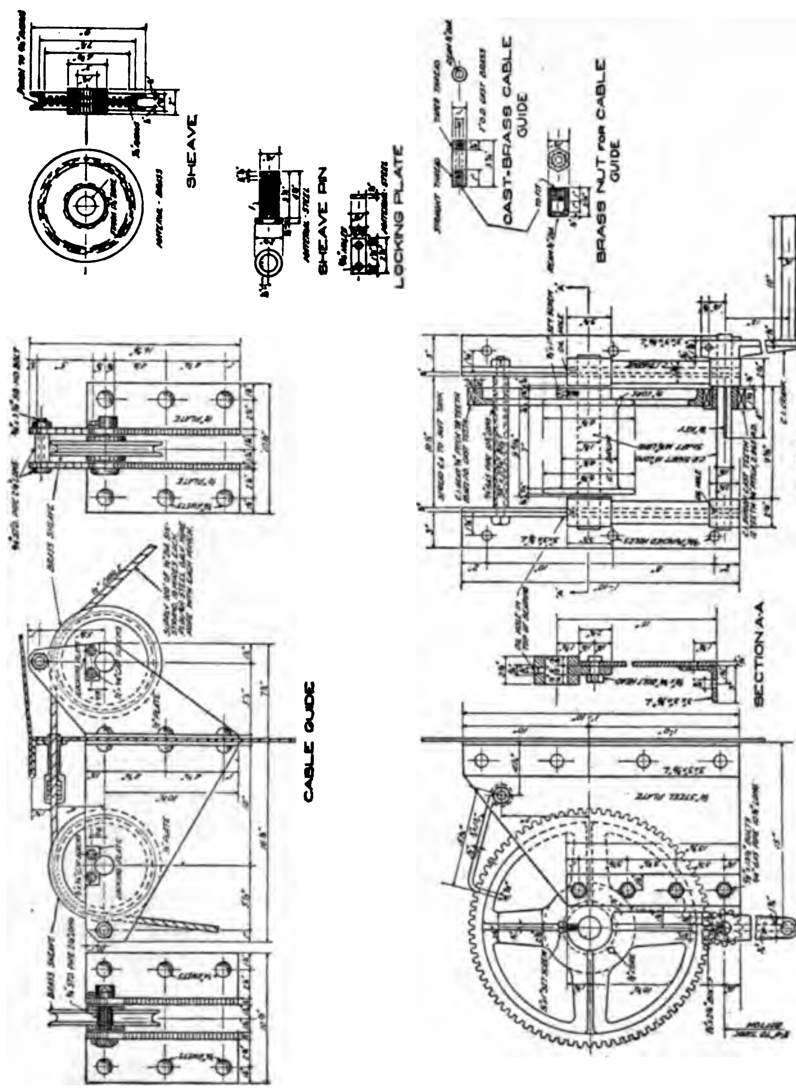


Fig. 161—Specification of fire wall

is gone, the wind will often wreck the sheathing and rafters as well.

Wooden roofs and wooden roof supports are objectionable also as regards fire hazards. Although it may be possible to extinguish burning oil in a tank by steam or blanket of foam, neither of these methods is necessarily effective in putting out a fire on the roof, so that smouldering embers may be continually dropping back into the tank only to reignite the whole mass, no matter how often the blaze alon gthe surface of the oil may have been quenched.



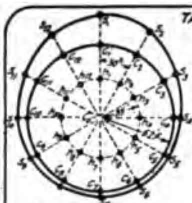
GEARED WINCH AND CABLE GUIDE FOR SWING-PIPE CABLE
Fig. 160

TANK GRADE NO. 765

Diameter 125'-for 55 000-Barrel Tank

"Rod reading at "Grade" = 11.5"

Azimuth	35' Radius Rod	35' Radius Cut h	62.5' Radius Rod	62.5' Radius Cut C			Slope Stakes Radius	Slope Stakes Rod	Slope Stakes Elev. s	Cs	Cs^2
0°	6.0	5.5	7.9	3.6			67.5	8.2	3.3	11.9	39.3
30°	5.7	5.8	7.9	3.6			67.3	8.3	3.2	11.5	36.8
60°	5.4	6.1	7.4	4.1			69.1	7.1	4.4	18.0	79.4
90°	4.6	6.9	6.2	5.3			70.0	6.5	5.0	26.5	132.5
120°	3.9	7.6	3.9	7.6			73.9	3.9	7.6	57.8	439.0
150°	3.5	8.0	2.0	9.5			77.1	1.7	9.8	93.1	912.4
180°	3.8	7.7	2.6	8.9			77.1	1.8	9.7	86.3	837.4
210°	4.9	6.6	5.1	6.4			72	5.2	6.3	40.3	253.9
240°	6.4	5.1	8.4	3.1			66.7	8.7	2.8	8.7	24.4
270°	7.2	4.3	10.2	1.3			62.5	—	—		
300°	6.9	4.6	9.3	2.2			62.5	—	—		
330°	6.3	5.2	8.1	3.4			65.6	9.4	2.1	7.1	14.9
Sums		73.4		59.0						361.2	2770.9
Factors		20.92		13.		Total Vol:				.909	.007272
		1.5		177		$47.4\ C_0$ =	289.1			3.3	.01
		66.1		590		$20.92\ \Sigma h$ =	1535.6			325.1	.19
		1468.		767.0		$13\ \Sigma C$ =	767.0			328.4	.55
		1535.6				$.909\ \Sigma Cs$ =	328.4				19.39
Center	Cut =	$6.1 = C_0$				$.007272\ \Sigma Cs^2$ =	20.1				20.14
	47.4				Total Excavation		2940.7	Cu. Yds.			
	6.1										
	4.7										
	284.4										
	289.1										



TANK GRADE 125' DIAMETER FOR 55 000-BBL. TANK

Find in Field:

Cut at center, = C_0 (ft.)

Cuts at circumference, 30° apart, = $C_1 \cdot C_2 \cdots C_{12}$ (ft.)

Cuts at 35 ft. radius, 30° apart, = $h_1 \cdot h_2 \cdots h_{12}$ (ft.)

Elevations of slope stakes, $s_1 \cdot s_2 \cdots s_{12}$ (ft.) above grade.

Side slope $1\frac{1}{2}:1$

Volume, Cubic Yards:

$$V = 47.4\,C_0 + 20.92\,[h_1+h_2+h_3+\cdots h_{12}] + 13\,[C_1+C_2+C_3+\cdots C_{12}]$$
$$+\ 0.909\,[C_1s_1+C_2s_2+C_3s_3+\cdots C_{12}s_{12}]$$
$$+\ .007272\,[C_1s_1^2+C_2s_2^2+C_3s_3^2+\cdots C_{12}s_{12}^2]$$

Or, Vol. of excavation in Cu. Yds. equals – 47.4 times center cut + 20.92 times sum of cuts on 35 ft. radius + 13 times sum of cuts at 62.5 ft. radius + .909 times sum of products of each cut at 62.5 ft. by its corresponding slope stake elev. + .007272 times the sum of the products of each cut at 62.5 ft. by the square of its corresponding slope stake elev.

The calculation may be most simply made in tabular form, by adding two columns, for Cs and Cs^2, to the ordinary field notes, adding up cols. and multiplying sums by factors given. Take cuts to nearest tenth of a foot.

If cuts at 35' radius are not taken, formula becomes:

$$V, \text{Cu. Yd.} = 25.25\,[6C_0 + C_1+C_2+C_3+C_4+\cdots C_{12}]$$
$$+\ .909\,[C_1s_1+C_2s_2+C_3s_3+\cdots C_{12}s_{12}]$$
$$+\ .007272\,[C_1s_1^2+C_2s_2^2+C_3s_3^2+\cdots C_{12}s_{12}^2]$$

The above to be used only for sections 30° apart, slope $1\frac{1}{2}:1$, and radii as above.

TANK GRADE 105' DIAMETER FOR 37 500-BBL. TANK

Find in field:

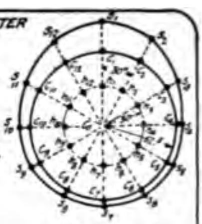
Cut at center = C_0

Cuts at circumference, 30° apart, = $C_1 \cdot C_2 \cdots C_{12}$ (ft.)

Cuts at 30 ft. radius, 30° apart, = $h_1 \cdot h_2 \cdots h_{12}$ (ft.)

Elevations of slope stakes, $s_1 \cdot s_2 \cdots s_{12}$ (ft.) above grade

Side slope $1\frac{1}{2}:1$



Volume, Cubic Yards:

$$V = 34.9\,C_0 + 14.81\,[h_1+h_2+h_3+\cdots h_{12}] + 9\,[C_1+C_2+C_3+\cdots C_{12}]$$
$$+\ 0.7636\,[C_1s_1+C_2s_2+C_3s_3+\cdots C_{12}s_{12}]$$
$$+\ .007272\,[C_1s_1^2+C_2s_2^2+C_3s_3^2+\cdots C_{12}s_{12}^2]$$

GENERAL FORMULA, SMALL TANK-GRADES

Radius of Grade = R ft.

Cuts at circumference 30° apart = $C_1 \cdot C_2 \cdots C_{12}$ ft.

Center cut = C_0 ft.

Slope stake elevations = $s_1, s_2, \cdots s_{12}$ ft. above grade

Volume, Cubic Yards:

$$V = .006464\,R^2\,[6C_0 + C_1+C_2+C_3+\cdots C_{12}]$$
$$+\ .014544\,R\,[C_1s_1+C_2s_2+\cdots C_{12}s_{12}]$$
$$+\ .007272\,[C_1s_1^2+C_2s_2^2+\cdots C_{12}s_{12}^2]$$

The above apply only for sections 30° apart and other conditions as stated.

Fig. 160B.—Specimen field notes for tank grade work

The derivation of these formulas is too tedious to be given in detail, but it may be outlined as follows:

(1) The cylindrical figure whose horizontal projection is the base of the grade is made up of a number of prisms, the area of whose horizontal bases are known from the conditions assumed, and whose vertical edges are the 'cuts.' The volume of these prisms are calculated, the cuts being represented by the letters shown on the diagram, added together, and reduced to cubic yards.

(2) The ring, of varying triangular section, outside of the cylinder, is treated as follows: The area of the triangular section at each 30° line is expressed in terms of the cut at the edge of the base and the elevation of the slope-stake (set where the excavation meets the natural surface), the slope of the bank being given. The distance from the center of the grade to the centre of gravity of this triangular is found in terms of the same quantities and the radius of the grade, and the volume generated by swinging the triangle through 30° calculated according to Guldin's principle. The volumes thus found are added together, reduced to cubic yards, and added to the volume found in (1).

The formulas apply equally well to a grade that is to be made entirely in fill, by substituting "fill" for "cut" throughout. Tank grades should never be built in both cut and fill, for obvious reasons.

Contract Specifications for Construction of 750,000 Barrel Concrete Lined Reservoir[1]

Definition.—The —— Company in itself, or by its duly authorized representative, shall be referred to in these specifications as the "company."

The firm undertaking to furnish the material and erect the reservoir as herein specified, in itself, or by its duly authorized representative, shall be referred to in these specifications as the "contractor."

At all times during the progress of the work the contractor shall designate some person as his representative to whom instructions may be given by duly authorized representatives of the company.

Drawings.—The drawings listed below, showing the details of

[1]Bulletin of U. S. Bureau of Mines. Bulletin No. 155.

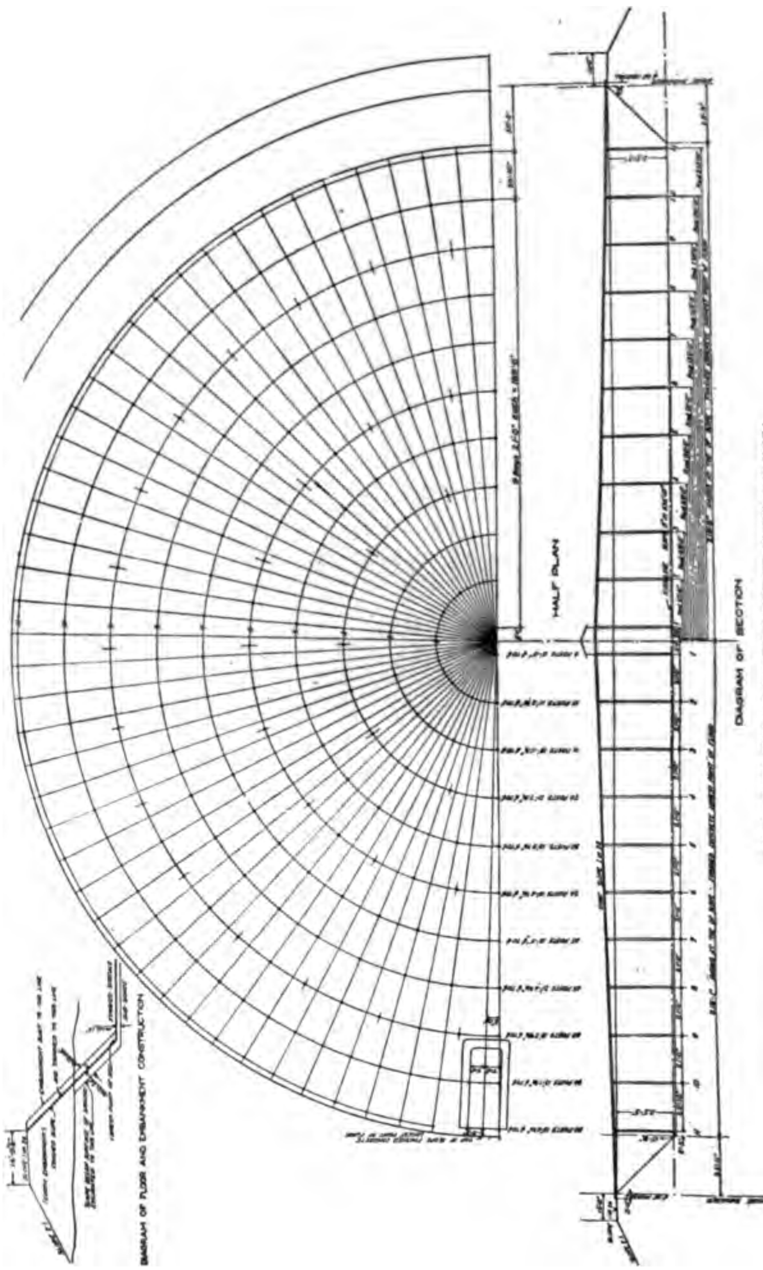

HALF PLAN
DIAGRAM OF SECTION
DIAGRAM OF FLOOR AND EMBANKMENT CONSTRUCTION

Fig. 162

the construction of the resrvoir, are hereby made a part of these specifications: Figs. 162 to 165.

The drawings and specifications are intended to supplement each other, so that the work described in the drawings and not mentioned in the specifications, or vice versa, is to be executed by the contractor as if it were both mentioned in the specifications and shown on the drawings.

Shape and plan of construction.—The reservoir shall be circular in plan, as shown on Fig. 162, and shall be constructed by making an excavation and construction around the excavation, with the excaavted material, an earthen embankment. The area within the inner crest of the embankment shall then be covered with a wooden roof, after which the bottom an dthe sides of the place inclosed shall be lined with concrete.

Dimensions, slopes, areas and capacity of embankments.—The dimensions of the reservoir are as follows:

Inside diameter at top, 488 feet.

Inside diameter at bottom, 437 feet 6 inches.

Maximum depth, approximately 25 feet 11 inches.

The slopes of the embankment shall be as follows:

Slope of embankment inside reservoir, 1 horizontal to 1 vertical.

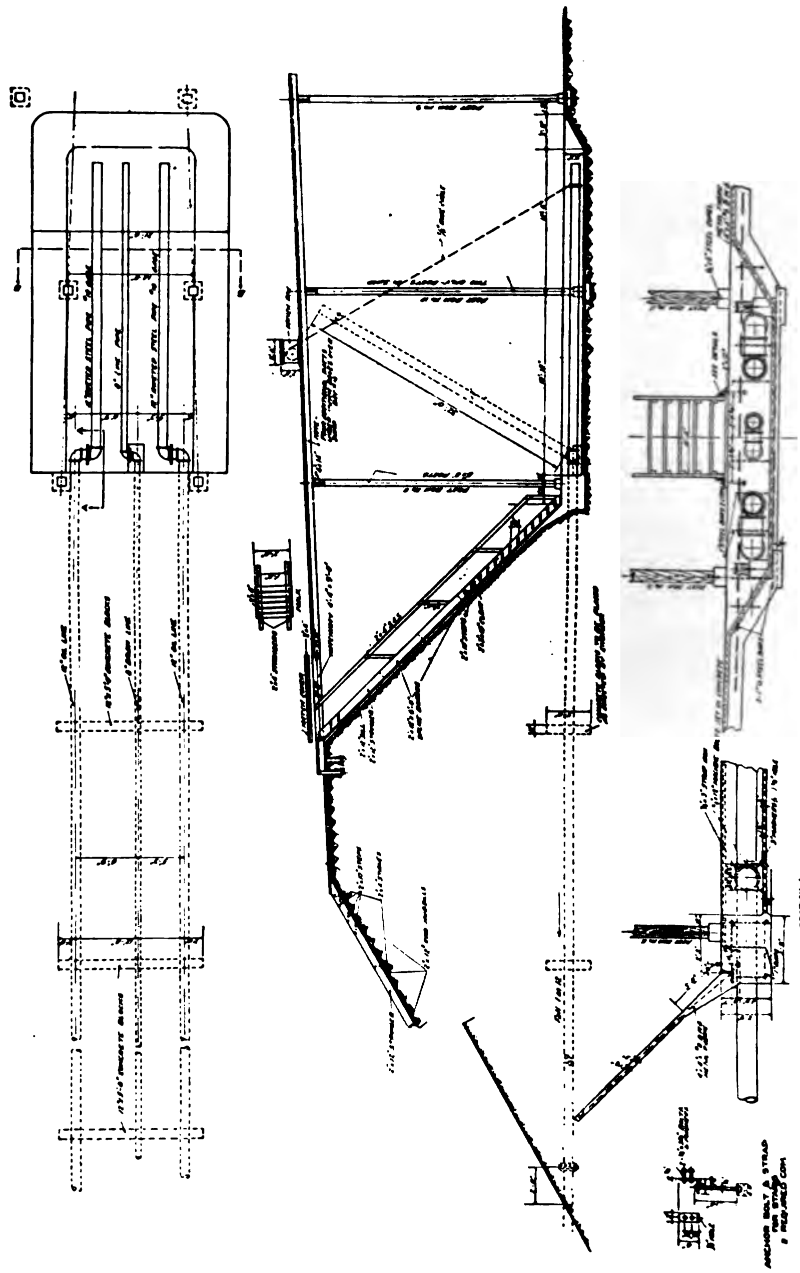
Slope of embankment outside reservoir, 2 horizontal to 1 vertical.

Slope of embankment top of reservoir, 24 horizontal to 1 vertical.

The width of the embankment on top shall be 15 feet. The area of the bottom will be approximately 150,330 square feet. The area of the sides will be 53,200 square feet; total area, 203,530 square feet; capacity in barrels of 42 gallons each, approximately 750,000.

Workmanship.—All work in connection with the construction must be done in a workmanlike manner, and to the entire satisfaction of the company or its duly authorized representatives.

Inspection of material.—All material furnished by the contractor as herein specified shall be of the best of its respective kind, and shall at all times be subject to inspection by the company or its duly authorized representative, and any material that shall be found defective and be condenmned by the company must be removed immediately by the contractor and be replaced by acceptable material.



DETAILS OF SUMP AND SWING PIPE FOR 750,000-BARREL CONCRETE-LINED RESERVOIR.

Fig. 163

Damages.—The contractor shall at all times be responsible for damages to material that is stored in the vicinity of the reservoir site during the progress of construction, and the contractor shall make good such damaged material by supplying new material from time to time at his own cost and expense as directed by the company. The contractor shall also be responsible for any damages done to the reservoir, or any part of it, or to any property of the company upon which the reservoir is situated, caused by the carelessness or negligence of any of his employes. The contractor shall also be liable for all damages to tools, implements and equipment furnished by him during the progress of the work.

Care of men.—The contractor shall have complete responsibility for the care of the men in his employ ,and shall be liable for all damages by accident to such employes. He shall furnish the necessary commissary for feeding his men, and shall provide necessary tents, temporary houses, and equipment for sleeping quarters.

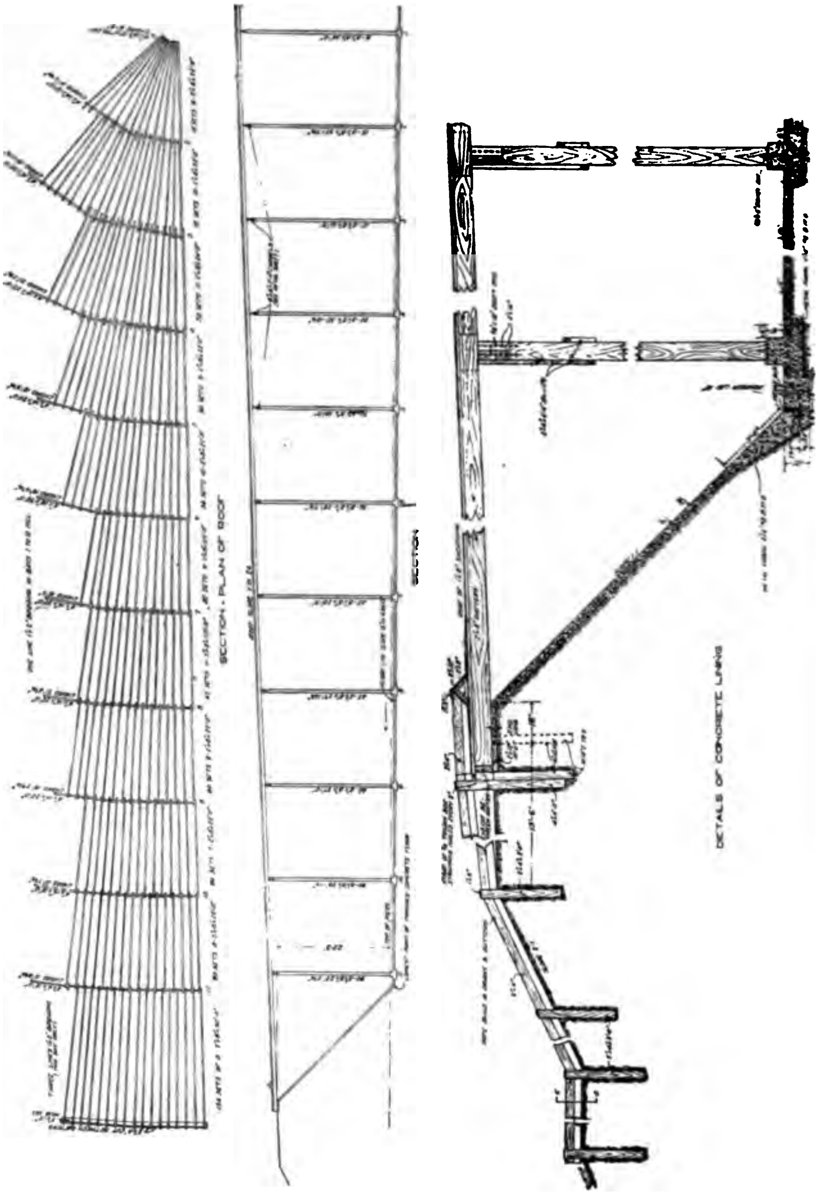
Incompetent employes.—The contractor shall furnish only such men for the prosecution of the work as are competent in their particular line of employment. If any employe is judged incompetent by the company or its duly authorized representative then the contractor shall immediately remove such employe and shall not again employ him on the work.

EARTHWORK

Nature of the work.—The work to be done under this section consists of excavating the necessary earth from the interior of the reservoir and depositing such excavated material in the embankments surrounding the reservoir, in accordance with plans hereto attached.

Equipment.—The contractor shall supply all the necessary labor, tools, and equipment. including picks, shovels, drills, "fresno" scrapers, road machines, tampers, and teams, and whatever equipment is necessary for properly carrying on the work.

Grade stakes.—The company shall place grade stakes wherever required about the reservoir, and the completed excavations and fills shall conform truly to the slope and outline as determined by such grade stakes, and the company shall not be responsible for nor shall it pay for any work that does not conform to such grade


SECTION - PLAN OF ROOF
SECTION
DETAILS OF CONCRETE LINING

stakes. The contractor and his employes shall at all times exercise due caution in caring for grade stakes as set by the company, and any employe willfully destroying such stakes shall be immediately discharged by the contractor.

Excavation.—The exact amount of excavation shall be governed by the material that must be excavated, and shall be determined by the company from time to time during the progress of the work. Should it be necessary in the opinion of the company to excavate more material from the reservoir than originally intended, or to excavate material from borrow pits, the exact amount of such excavation shall be carefully determined by the company by cross section, and the additional yardage shall be paid for at the same rate as the yardage from the original excavation.

Stripping the surface soil.—The contractor shall first strip the entire surface of the reservoir, both that portion of the cut and that portion to be covered by embankment, of all vegetable matter and surface soil. This stripping of the site shall extend to a depth of at least 8 inches below the surface and to whatever depth may in the judgment of the company be required. The material so stripped shall be removed from the area and placed in fire levees surrounding the reservoir site, or at other points in the vicinity of the reservoir, as directed by the company.

Oil and water drains.—Two 12-inch lines and one 8-inch water drain shall be placed beneath the embankment, as shown on Fig. 163, at such positions as shall be designated by the company.

Ditches for these pipes shall be dug by the contractor immediately after the surface soil has been stripped. Pipe shall be furnished and laid by the company. The contractor, however, shall do the work of backfilling the ditches, also of placing the concrete blocks, as shown on Fig. 163.

Building up the embankment.—The area beneath the embankment shall be plowed by the contractor, thoroughly harrowed, and moistened with water to the satisfaction of the company. The embankment shall then be built with material excavated from within the reservoir, or, if need be, from pits in the vicinity of the reservoir. The material may be excavated and placed in the embankment by wheel scrapers, "fresno" scrapers or wagons. It shall, however, not be deposited in layers more than 3 inches thick, and where necessary road machines shall be employed to insure the proper spread-

ing of the material in the embankment. Under no conditions shall material be dumped onto the embankment and not spread.

All material placed on the embankment shall be moistened with water before being loaded into the scrapers or wagons, and shall again be moistened after being spread. Any excavated material from within the reservoir that, in the judgment of the company, is not fit to be placed in the embankment shall be placed by the contractor at a point outiside the reservoir site, as designated by the company.

When the material has been placed in thin layers in the embankment and moistened as specified, it shall then be tamped by at least two tampers of the sheep's foot type. Each tamper shall be drawn by a 4-horse team, and shall be driven around the top of the fill, making at least 10 complete circuits of the reservoir per hour.

Water for wetting material shall be furnished by the company, and shall be brought by the company in water mains surrounding the outer circumference of the reservoir and at a distance of about 20 feet of the outside toe of the embankment. The contractor shall furnish and shall lay all necessary laterals from this water main into the reservoir site, and shall move such laterals from time to time as may be required by the progress of the work.

Borrow pits.—Where necessary, borrow pits shall be designated by the company in the vicinity of the reservoir site. The nearest rim of such a borrow pit shall be at a distance of not less than 200 feet from the outer toe of the reservoir embankment, and the farthest rim of such a borrow pit shall be at a distance not to exceed 400 feet from the toe of the embankment. If it is necessary to locate a borrow pit so that its nearest rim is a greater distance than 600 feet from the outer toe of the embankment, the contractor shall receive extra compensation for the removal of such material as shall be determined on at the time.

Runways to embankment.—In the construction of the embankment the contractor shall build runways for the removal of the material from the excavation inside the reservoir to the embankment. These runways shall be located by the company, and shall be spaced at a distance not less than 100 feet apart. The scrapers, wagons, teams, etc., in carrying the dirt from the excavation to the embankment shall be driven up one runway and shall return to the

excavation along the top of the embankment and down the next adjacent runway.

The inside slope.—To obtain a homogenous and compact surface to the inner slope of the embankment, the inner slope shall be built and finished in the following manner. The embankment of the reservoir shall first be built up as above provided in these specifications. The excavation shall be so made that the inner slope shall be about the width of a wheel scraper beyond the line of the desired finished slope, beginning at the bottom of the reservoir which shall be excavated for a distance of about one foot below the position of the concrete lining. The inner slope shall then be built up by material excavated from within the reservoir, deposited by wheel scrapers in thin horizontal layers, and shall be moistened and thoroughly tamped by sheep's foot tampers. This inner embankment, or earthen lining, shall be bound to the original embankment and slope by first plowing and otherwise roughening the original slope and embankment. When this lining is thus built up it shall be allowed to stand for at least 3 days before being trimmed to grade. The inner face of the embankment so built up shall then be trimmed to a true and even slope to conform with the dimensions of the reservoir herein set forth.

Top of the embankment.—The top of the embankment shall be built at least 2 inches higher than the finished top, and shall be made smooth and even and brought to proper grade.

Outside slope.—As herein specified, the outside slope of the embankment shall be 2 horizontal to 1 vertical. It shall be built up compactly, and neatly finished. and upon completion shall be oiled by the contractor for a distance of three feet beyond the toe of the embankment. Oil shall be furnished by the company on the ground and the contractor shall furnish the necessary equipment for sprinkling the oil on the embankment.

Bottom of reservoir.—The bottom of the reservoir shall be excavated to a subgrade one foot below the finished grade. It shall then be thoroughly plowed, harrowed, moistened and compacted. Suitable filling material shall then be spread over it to bring it up to the finished grade. The filling material shall be spread on in thin layers as specified for the embankment, and shall be thoroughly moistened and rolled. The roller used on this work shall have a smooth surface, and shall weigh no less than 5 tons.

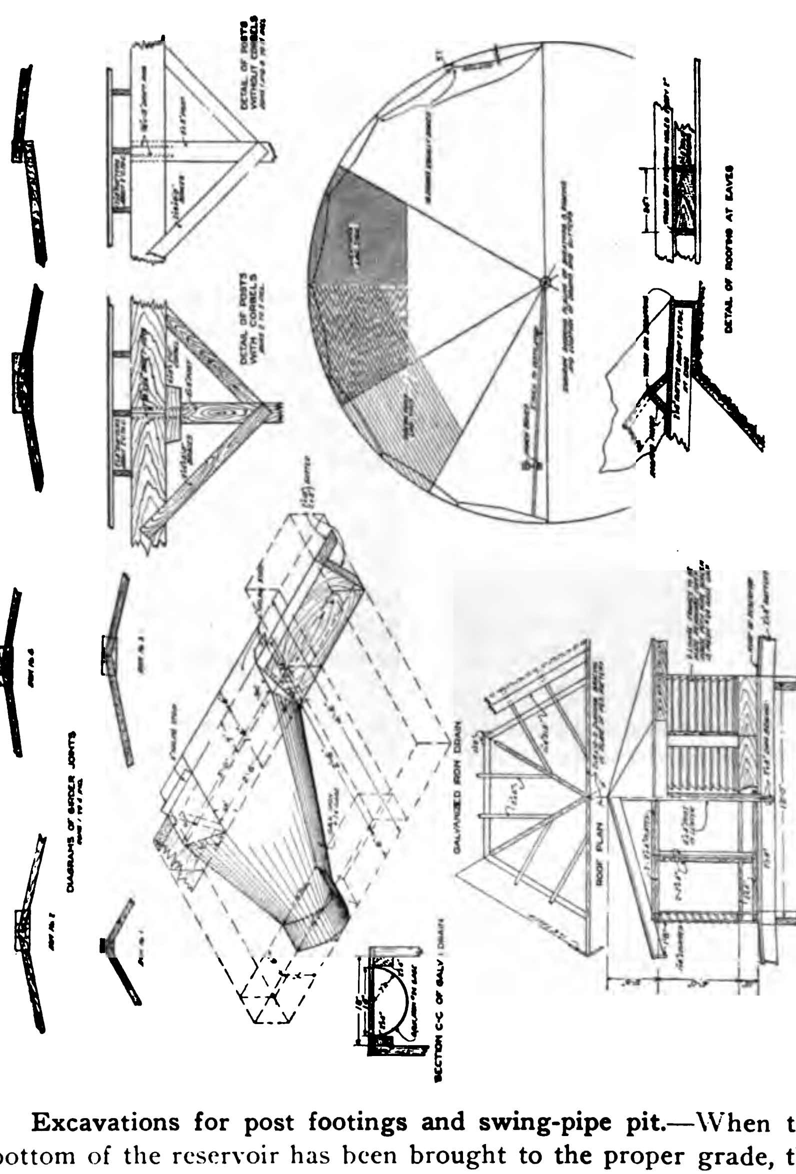


Fig. 165
DETAILS OF ROOFING FOR 76,000-BARREL CONCRETE-LINED RESERVOIR.

Excavations for post footings and swing-pipe pit.—When the bottom of the reservoir has been brought to the proper grade, the contractor shall make excavations for the concrete footings for the posts, for the swing-pipe pit, and for the joint between the floor and the side slabs as designated by the company. The contractor shall remove from the inside of the reservoir all such material excavated,

and shall place it at positions designated by the company or its authorized representative.

Extra work.—Extra work unless otherwise stated shall be done by force acocunt, but under no conditions shall extra work be performed by the contractor, or paid for by the company, without written authority from the company.

ROOF

Nature of the work.—The work to be done, under this section, consists in the erection of a wooden roof over the reservoir as herein specified, and in accordance with the drawings hereto attached.

Material and equipment.—The contractor shall supply all the necessary material, equipment and labor for the construction of the roof. All such material shall be the best of its respective kind, and shall be subject at all times to the inspection of the company or its duly authorized representative. It shall conform to the sizes as designated on the drawings.

Roof supports and their piers.—Roof supports shall be wooden posts 8 by 8 inches, as designated on Figs. 164 and 165. The posts shall rest on concrete piers as shown on the drawings, and shall be centered by one dowel pin 5/8 inch by 6 inches, in each pier. For the convenience of the contractor piers may be poured in two sections, one pouring bringing the pier flush with the surface of the ground, after which the reinforcement fabric for the bottom may be placed in position, and the second pouring may be made, bringing the top of the pier to the desired grade and having the floor fabric embedded in it at the proper point so that fabric may form a continuous reinforcement for the floor slabs. The tops of the piers on the bottom of the reservoir shall be on the same plane and they shall be kept damp for at least 6 days after having been poured before posts may be erected on them.

Roof girders.—The girders shall be of 4-inch by 14-inch material, and of lengths as shown on Figs. 164 and 165. They shall be fastened to the posts with ⅝-inch by 18-inch drift pins. Girders and posts shall be fastened by braces, as shown on drawings, of 2-inch by 6-inch material. Knee braces shall be bolted to posts and girders by at least two 3/8-inch carriage bolts Corbels,

as shown on Fig. 165, shall be placed on top of posts in rows of 2, 3, 4 and 5, and shall be drifted through with 5/8-inch by 24-inch drift pins, as shown.

Rafters and mud sills.—All rafters shall be of 2-inch by 8-inch material, and of lengths as shown on the drawings. The outer row of the rafters shall rest on a 2-inch by 12-inch redwood mud sill, as shown on Fig. 164, and shall be notched so as to bear on the full width of the mud sill. A line of 2-inch by 12-inch double bridging shall be placed between the rafters in the middle of each bay, with the exception of the bays on the outer row. In the outer row of bays three lines of such bridging shall be placed as directed by the company. Bridging shall be nailed in position before the sheathing is put on, and two 10d nails shall be used in the end of each bridging. The rafters shall be toe-nailed to the girders with 10d nails, using at least three at each rafter. Rafters that lap shall be thoroughly spiked with 20d spikes, and where joints abut shall be spliced with 2-inch and 8-inch material and thoroughly spiked. The space between rafters at the embankment shall be completely closed by 2-inch by 8-inch material.

Sheathing.—The roof shall be sheathed with 1-inch by 8-inch sheathing surfaced on one side, furnished in assorted lengths from 8 feet to 16 feet. Sheathing to be No. 1 material, free from knots, pitch pockets, or shakes. The roof shall be laid, as shown on Fig. 165 to break joints with roof paper.

Before the sheathing is laid the top rafters shall be trimmed off with adzes where necessary to insure that sheathing will rest securely on each rafter and will lie smooth and flat. A space of approximately 3/8-inch shall be left between each board to allow for swelling and shrinkage. Each board shall be nailed with at least three 8d penny nails on each rafter. All the roof supports and the sheathing, with the exception of a ring approximately 10 feet in width around the circumference of reservoir, necessary for handling the concrete materials, shall be placed in position before any of the concrete material other than the posts footings shall be poured.

Ventilator, ladders, walk, hatch, etc.—One ventilator, as shown on Fig. 165 shall be constructed on the roof at the center of the reservoir. Contractor shall also place a stairway from the bottom of the stairway to the top of the inside as designated on Fig. 163 and one stairway from the outside toe of the slope to the top of the

embankment, to be located in the field by the company. A wooden walk way shall be constructed by the contractor from the edge of the roof to the center, having branches to the winch boxes. This wooden walk way shall be composed of 2-inch by 4-inch stringers, and by 2-inch by 8-inch planks 2 feet wide, laid with intervening spaces of about ½-inch. The roof of the tank is also to be equipped with a properly constructed hatch place at the head of the stairway as shown on Fig. 163.

Nails—The contractor shall furnish all nails required in the work, to be of sizes as designated in the specifications and drawings.

Roofing paper.—When the woodwork of the roof has been completed, before any roofing paper shall be placed in position, the sheathing shall be thoroughly swept and cleaned of all sawdust, dirt, chips, shavings, or other material, particular care being taken that no nails are left lying on, or partly imbedded in, the roof. All loose or projecting knots shall be removed, and knot holes exceeding 1 inch in diameter shall be covered with tin plates securely nailed on. The sheathing shall then be covered and made water-tight by placing the layer of 3-ply roofing paper of a quality to be approved by the company or its duly authorized representative. This paper shall be laid in accordance with Fig. 165. Laps of paper shall be thoroughly cemented together and then nailed with No. 12 roofing nails, the maximum spacing between nails to be 1½-inches.

After the roofing has been laid in place, no unnecessary material of any sort shall be wheeled or carried over it, or stored upon it, and as little walking as possible shall be done upon it.

Asphalt and gravel coating.—When the roofing has been placed in position as above specified, a heavy coating of hot ashphalt, at least 3½ pounds per square yard being used, and a coating of hot gravel shall immediately be applied to the ashphalt. As much gravel shall be used as is held by the ashphalt. After cooling, the excess loose gravel shall be removed. Particular care must be taken that hot gravel is applied to hot ashphaltum, and that a thorough bond is made between the gravel and the ashphalt. If such a bond is not made in any part of the covering, the contractor shall remove that part, including the roof paper, and shall replace it to the satisfaction of the company.

Roofing gravel.—The roofing gravel shall be furnished by the contractor. It shall be composed of pebbles rejected by a screen

having 3/32-inch openings and passing through a screen having 5/16-inch openings. Gravel shall at all times be subject to inspection by the company or its duly authorized representative.

Winch box.—The contractor shall install on the roof of the completed tank, as directed by the engineer, two standard iron winch boxes which will be furnished on the ground by the company.

Drains and gutters.—Gutters shall be constructed entirely around the outer edge of the roof, as shown on Fig. 165. The drains from these gutters and downspouts leading from the outer slope of the embankment shall be constructed as shown on Figs. 164 and 165. The galvanized iron drains shall be furnished by the contractor and shall be of No. 24 gage iron. The openings from the gutters to the downspouts shall be thoroughly and carefully flashed with roofing paper, and all joints shall be covered with hot ashphaltic cement so as to make a water-tight job. All drains leading down the slope of the embankment shall be constructed of wood, as per detail drawing, and shall extend at least 10 feet beyond the toe of the slope.

Cleaning up.—Upon completion of the roof, the bottom of the tank and the inside slopes shall be thoroughly cleaned of all small pieces of wood, roofing paper, nails, refuse, eac., which shall be disposed by the contractor as directed by the company.

CONCRETE

Nature of the work.—The work to be done by the contractor under this section consists of constructing upon the sides and bottom of the reservoir, in a thoroughly workmanlike manner, a lining of concrete 3 inches in thickness, reinforced with metallic fabric as hereinafter specified, and so carefully poured and compacted as to be nearly as possible water-tight. Under no conditions shall any of the concrete for the sides or floor be poured until the framework and sheathing of the roof, with the exception of the 10-foot strip around the circumference of the reservoir as hereinafter specified, shall have been erected. The piers for roof supports must, of course, be constructed before theh erection of the roof.

Materials, labor, tools, etc.—The contractor shall furnish all materials, labor, tools, mixers, barrows, carts, cars, skips, engines,

teams, wagons, etc., and any and all other tools and equipment necessary to perform the work as herein described.

Cement.—A good grade of Portland cement satisfactory to the company or its duly authorized representative shall be furnished by the contractor. Cement may be supplied either in sacks or in barrels, at the option of the contractor. It shall, at all times be subject to the inspection of the company, the company reserving the right to reject any and all cement that test shows to be not up to requirements.

Sand.—The contractor shall furnish the necessary sand for the contract. the sand must be clean and sharp and free from earth, clay, gypsum, mica, or other injurious material.

Rock.—Crushed rock shall be furnished by the contractor in sizes as follows:

One-half inch rock, which shall be retained on a ¼-inch mesh screen, and shall pass through a ½-inch mesh screen.

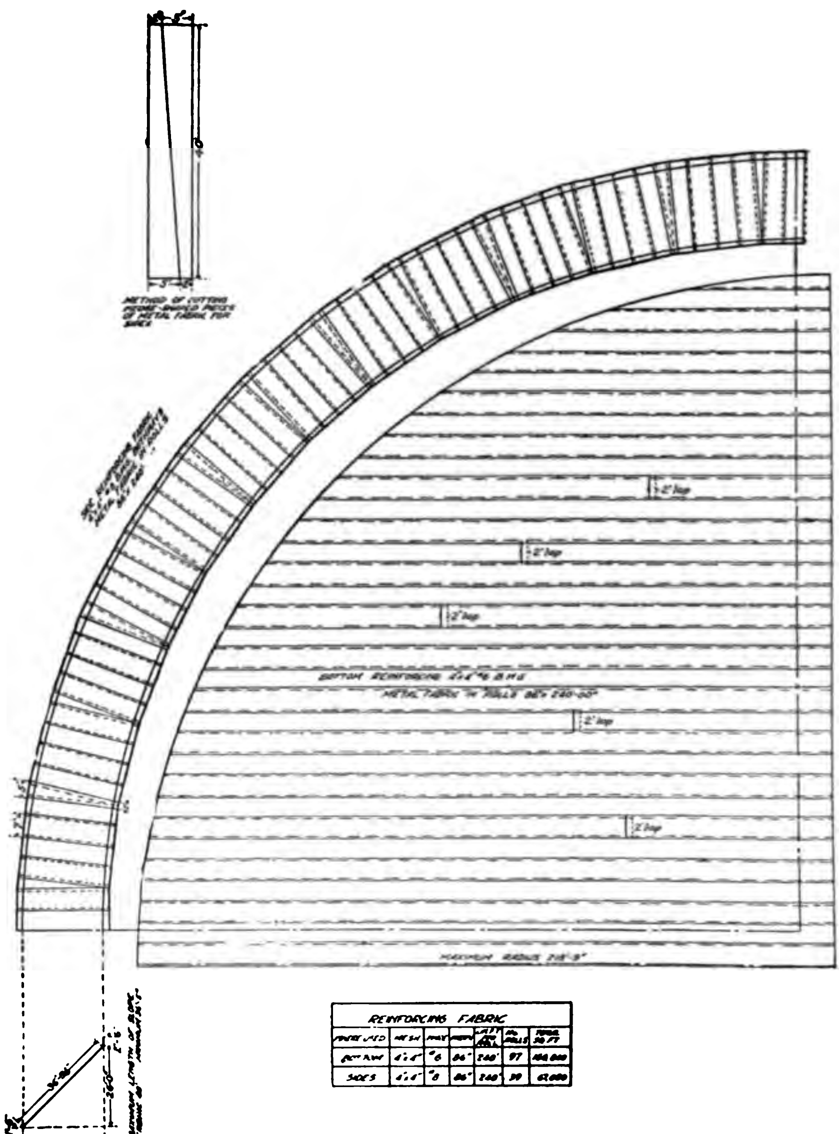
One-inch rock, which shall be retained on a ½-inch mesh screen, and shall pass through a 1-inch mesh screen.

It shall be of a quality approved by the company, and shall contain no clay or earthy substances or volcanic ash.

Reinforcing material.—The reinforcing material used on the bottom and sides of the tank shall be welded metal fabric, having a 4-inch by 4-inch mesh, and composed of No. 6 gage wire both ways. The fabric shall be furnished in rolls 86 inches in width and approximately 240 feet long. The contractor shall supply, cut and shape the reinforcing fabric.

Water for concrete.—The water for concrete shall be furnished by the company and shall be supplied through the water mains surrounding the outer circumference of the reservoir. The contractor shall furnish and lay all necessary laterals from these water mains to the various positions along the edge of the reservoirs where he may have his concrete mixers in operation.

Preparation of the reservoir for concrete.—The final preparation for the pouring of the concrete shall be made by carefully bringing all parts of the bottom and the inside of the reservoir to the finished grade. The contractor shall also at this time excavate for the joint at the toe of the slope and shall remove all material so excavated, together with all material taken off in finishing to exact grades from the inside of the reservoir.



ARRANGEMENT OF REINFORCING MATERIAL FOR CONCRETE-LINED RESERVOIR, CAPACITY 750,000 BARRELS

Fig. 166

Placing reinforcement.—All reinforcement fabric for the bottom of the reservoir shall be laid before the roof is put in place, and must extend continuously along the bottom and sides of the reservoir through the foundation piers for the posts. Longitudinal splices shall be lapped at least one mesh and shall be wired together with No. 16 gage annealed iron wire to be furnished by the contractor. All reinforcement must be properly stretched and allowed to lie flat. Transverse splices in reinforcement shall lap 24 inches. When the reinforcement is in place, and before pouring is begun, care must be taken that all stakes, pins, bolts, etc., used in laying and stretching the fabric are removed. The fabric must be so placed over the entire area that it can readily be pulled into position in the center of the concrete slab as the pouring progresses.

Joint at toe of slope.—A wooden joint 1 by 6-inch of concrete material shall be placed in the concrete at the toe of the slope inside the reservoir, as shown in detail on Fig. 163. The metal fabric laid upon the slope and the bottom of the reservoir shall pass through the wooden frame at the joint, as shown on the drawing, and shall be so laid as to form a continuous reinforcement, tying sides and bottom together.

Proportioning concrete material.—The concrete for the bottom of the reservoir and for the piers supporting the roof shall be composed of one part Portland cement, two and one-half parts sand, two parts of one-half inch crushed rock, and two and one-half parts of one-inch crushed rock. The concrete for the sides of theh reservoir shall be composed of one part of Portland cement, two and one-half parts of sand, and two parts of one-half inch crushed rock. The proportions of the various materials shall be very carefully measured at all times by the contractor. The company, however, reserves the right to change from this proportion as it sees fit, and no such changes shall in any way be construed to affect the contract price.

Mixing and pouring concrete.—The bottom of the reservoir and the side slopes shall be thoroughly wetted before any concrete material is poured on them. In sprinkling, however, the contractor shall see that no reinforcing fabric becomes soiled or muddy; and if any dirt does adhere to the fabric it shall be thoroughly removed before any concrete material is poured on it. The mixing shall be done in batch mixers of a form and type approved by the company.

No more water shall be added to the material than is absolutely necessary to cause the concrete to spread properly over the area to be covered. On both the floor and the side slopes a layer of concrete approximately 1½-inches thick shall first be poured. The reinforcing material shall then be drawn up through the concrete and allowed to rest on top of it. As soon as the fabric has been drawn up, and before the first layer has been allowed to set, a second layer shall be immediately poured, bringing the slab up to the required thickness. When the pouring has been completed, the surface of the concrete must be immediately tamped with wooden tampers and then finished smooth and close-grained by troweling. The contractor must at all times exercise especial care that the position of the wire fabric is as near as possible the center of the slab. He must also furnish men experienced in troweling and floating the surface of the concrete, in order that it may be made as nearly waterproof as possible.

Joints in concrete.—Upon the completion of a day's pouring the edges of concrete slabs shall be roughly beveled off. When work is resumed this beveled edge shall be thoroughly cleaned, dampened and well brushed with neat-cement grout before the next section of concrete is poured.

Sprinkling finished work.—The contractor shall keep all of the finished concrete moistened as directed by the company until the completion and acceptance of the reservoir by the company.

Grouting.—Should small shrinkage cracks appear in any part of the floor or slopes at any time during the concreting, they shall be filled with a cement grout as directed by the company. After the concrete has been allowed to stand for a period of 20 days, both the floor and the slopes shall be grouted with cement wash of a proportion to be determined by the company or its duly authorized representative.

Design and Construction of Concrete Fuel Oil Tanks[1]

The reservoir should be located a safe distance from inflammable structures as far as possible consistent with pumping requirements. If near buildings it should be covered with at least 18 inches of earth, to decrease fire hazards and also to minimize oil evapora-

[1]By H. B. Andrews, Consulting Engineer, Springfield, Mass. From Engineering and Contracting, Aug. 27, 1919.

tion. If distant from buildings, it should be at least half underground, and, if possible, the excavated material should be used in banking up around it.

The reservoir should be limited in size for two reasons: First, the necessity for not exceeding a day's working limit in operation of pouring concrete so that joints between operations may be eliminated, and second, so that in case of an accident or fire in any reservoir too much oil in storage will not be involved. This size limit should not be over 300,000 gallons under most conditions.

Reservoirs should be circular in shape, the better and more directly to take care of involved stresses and to avert danger of tensile or temperature cracks. They should be so proportioned and designed as to limit the number of pouring operations of concrete, in order to avoid joints between the operations.

Care should be taken to provide for all exterior stresses, such as hydrostatic pressure from groundwater, earth pressure on walls, and roof if reservoir is buried, and also to avoid as far as possible concentration of loads on walls or footings. Where joints are absolutely necessary they should be so protected that there will be no leakage through them. Regarding hydrostatic pressure, while enginners have found from tests that this pressure in soils is only about 50 per cent of the full head of water, it is not safe to design for stresses less than the full head, as any deflection in the concrete admitting a film of water between the earth and the concrete will produce the full hydrostatic pressure.

Concrete surfaces must be temporarily or permanently protected so that oil will not come in immediate contact with them if the concrete is less than six weeks old.

Falsework must be designed to hold concrete temporarily in place so that it will not tail or be distorted while placing concrete. It is especially necessary to provide for the firm holding of wall forms, as the pressure of several feet of concrete poured quickly as a monolith is intense, and any "give" of the forms after the concrete has obtained its initial set breaks up the crystals already formed and allows expansion of the concrete mass, with resultant porosity and loss of strength.

Concrete must be so designed that it will resist all exterior stresses to which it is subjected and so that it will be oilproof. One of the principal features of this design is to make the walls of cir-

cular reservoirs in tension sufficiently thick so that the ultimate strength of the concrete in tension will not be exceeded. It is not meant to leave out the steel reinforcement so that the stress will theoretically be borne by the concrete, but nevertheless it will be borne by it unless some unforeseen weakening of the concrete should throw it upon the steel.

An extended investigation, by the writer, on high circular concrete standpipes for water showed that if the concrete in the wall was stressed beyond its elastic limit, or ultimate strength, vertical air cracks will appear of sufficient width to admit water into the body of the concrete. This ultimate tensile strength in a 1:1½:3 concrete from tests made forthe writer at the Watertown Arsenal was 203 pounds per square inch. Where the concrete is in large sectional areas, and reinforced, this tensile strength will probably be somewhat higher. If a stress not exceeding 150 pounds per square inch is allowed in tension there will be no danger of these vertical cracks appearing.

Reinforcement must be so designed that it will take care of all interior and exterior stresses, and with fittings to hold it rigidly in place while the concrete is being poured. Steel in tension in walls should not be stressed over 10,000 pounds per square inch to conform with insurance company requirements. The writer does not think that it is necessary to figure the stress as low as this, under usual conditions, as he has satisfactorily constructed many reservoirs using a stress of 14,000 pounds. But the lower stress is an additional safeguard against inferior workmanship by inexperienced contractors and against any decrease in bond strength due to oil penetration of concrete. It is probably unwise to depart radically from insurance company recommendations. All reinforcing rods in concrete exposed to oil should be of a deformed section, for better bonding value.

For other parts of the reservoir the recommendations of the Joint Committee on Concrete and Reinforced Concrete should be followed.

The concrete should be no leaner than a mix composed of one part of cement, 1½ parts sand and 3 parts broken stone or gravel. To this mix should be added a "densifier." Hydrated lime has been found economical and satisfactory for this purpose, using 10 pounds of dry lime to each bag of cement. The stone must be hard and

clean, the best material being traprock, granite or gravel. The sand must be free from any deleterious matter, and should be well graded. Cement should be of an established quality.

The concrete should be deposited continuously in concentric layers not over 12 inches deep in any one place. No break in time over 30 minutes is permissible in depositing concrete during any one operation, and if any delay occurs amounting to 30 minutes or more the previous surface must be thoroughly chopped up with spades before the next layer of concrete is deposited.

The different operations in pouring are: (1) The pouring of the floor and footings; (2) the pouring of the entire walls; (3) the pouring of the roof. In small reservoirs the wall forms may be suported to the footings, floor and wall may be poured in one continuous operation. An approved joint or dam must be made between the floor and the wall.

Concrete should be mixed by a mixing plant of sufficient size and power to carry out each separate prearranged operation without danger of delay during the process. The materials should be mixed at least two minutes in the mixer, using just enough water to obtain a plastic mix without excess water coming to the surface after the concrete is deposited, and a measuring tank should be used so that the amount of water may be kept uniform.

The concrete when deposited in forms should be well spaded by at least four competent laborers who are not afraid to use their muscle in compacting the concrete thoroughly and working out the trapped air bubbles.

Reinforcement should be of round deformed medium steel bars. These bars should be bent or curved true to templets carefully placed in their predesigned location, and rigidly maintained there by mechanical means. No laps should be less than 40 diameters and no two laps of adjacent rods should be directly opposite each other.

The forms should be of good material, strongly made and so braced, or held in place by circumferential bands, that no distortion allowing displacement of concrete during its initial set is possible.

The surface of the floor should be troweled smooth as soon as it can be properly done.

Concrete designed and placed as recommended herein is practically oil-tight, but as oils are somewhat detrimental to fresh con-

crete it is advisable to put on an interior wash or coating to protect the fresh concrete from the action of the oil, for such a time as may be necessary for it to cure and harden sufficiently. Silicate of soda, while not a permanent coating, has been used satisfactorily for this purpose according to the following specification for oil-proofing:

The surface of the floor and the interior surface ofthe wall are to be coated with silicate of soda of a consistency of 40° B., and applied as follows:

First coat—One part of silicate of soda and three parts water, applied with brush, and all excess liquid wiped off with cloth before drying.

Second coat—One part of silicate of soda and two parts water applied as above.

Third coat—One part silicate of soda and one part water, applied with brush and allowed to dry.

Fourth coat—Applied same as third.

FIRE HAZARDS AND PRECAUTIONS ABOUT TANK FARMS[1]

Tank construction.—All tanks about tank farms and refineries should be of steel construction throughout, with gas-tight roofs on steel roof supports. Tank stairways should also be of steel. Gage holes should be fitted with tight iron caps, which can be screwed down and will prevent the escape of gas. Swing pipe lines should pass through stuffing boxes. These boxes should be kept at all times in gas-tight condition. A vent pipe of proper size should lead from a point near the apex of the roof down the side of the tank, and thence underground on a true gradient to a point outside the fire levee, where it should terminate in a vertical standpipe at least 20 feet high. This pipe should be so laid that the lowest point is the bottom of the standpipe, where a small drain should be provided to remove any possible accumulation of water or condensate from the gases. A tee having each run closed with a fine meshed wire gauze, should be "bull-headed" into the top of the standpipe.

As has been previously mentioned, an arrangement whereby gases from vent pipes would be passed through an absorber con-

[1] C. P. Bowie in U. S. Bureau of Mines Bulletin No. 170.

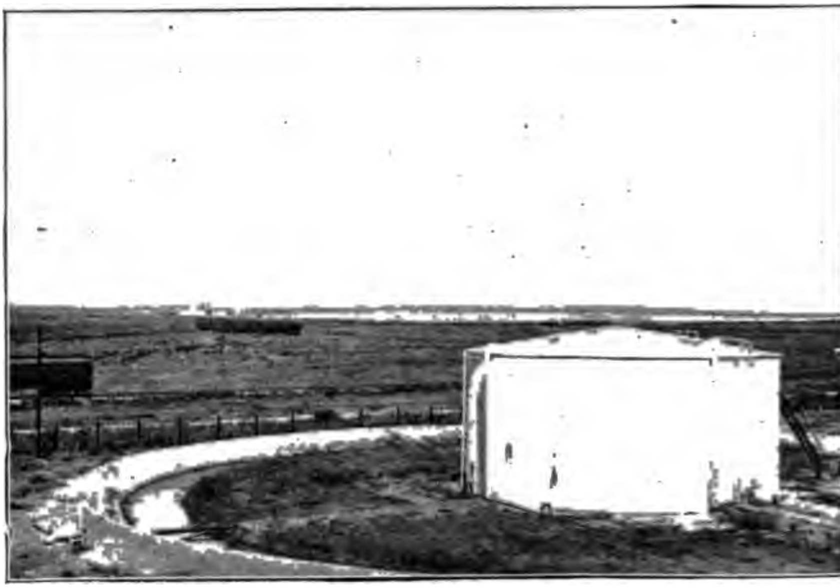
denser or otherwise profitably utilized would be far better than releasing the gases to the atmosphere.

Pipe lines.—Pipe lines connecting storage tanks should be underground for at least part of the distance, or otherwise thoroughly grounded. The writer has been unable to find any instance where a tank has been ignited from lightning following exposed piping, but such a condition might easily exist. Therefore it is a wise precaution to bury the pipes in the ground, or in some localities, even placing insulating joints in them.

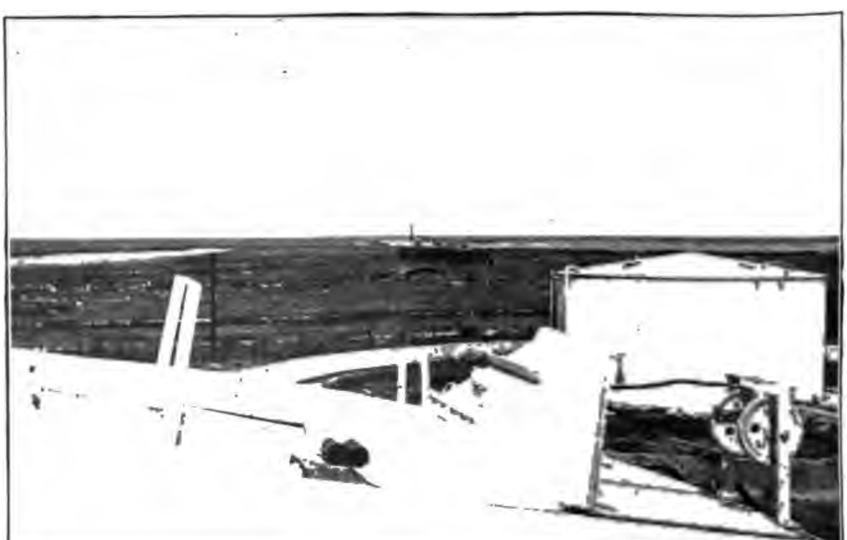
Loading stations.—Fires are said to have been caused at loading stations, where ships discharge or take on oil, through electrical sparks formed when connection to the ship was being made or broken. The writer has been unable to find any instance where the origin of the fire was actually traced to this cause, but it is quite possible that fires could be started in this way, especially where the pipe lines leading from the wharves pass near power lines, electric railways, etc. Most companies ground their loading pipes at the wharf. This is done by soldering a copper wire to the pipe; the other end of the wire is attached to a copper plate, which is sunk in the mud beneath the water.

Suction pipes.—All tanks should be provided with large suction pipes so that in case of fire as much oil as possible can be removed to other tanks or reservoirs. Tanks containing crude oil should also be provided with bottom drains, connected with pipes discharging at a safe distance from the tank. As the tank burns, these drains should be kept open to remove the water that settles from the oil. This precaution is very important, as a small amount of water in the bottom of a tank when converted into steam will cause the tank to boil over violently and the blazing froth may be carried by the wind along the ground and over the top of the fire levees, spreading the fire to other tanks or structures.

Levees.—Where possible, tanks should be surrounded with a dike or levee of sufficient height to hold one and a half times the capacity of the tank. Each tank having a capacity of 5,000 barrels or more, which is used for the storage of oil, should be placed at least 300 feet, measured from shell to shell, from any other tank, and at least 150 feet from derricks, buildings or other inflammable structures.



A. Arrangement of gas vents from "all steel" tanks



B. Explosion door for "all steel" tank
Fig. 167.

For a distance of at least 150 feet from the tank the ground should be kept free from weeds, grass and rubbish.

Lightning rods.—The writer has made many inquiries among operators regarding the use of lightning rods, but has been unable to find any instances where there is proof that their use has prevented a tank or other structure from being struck. The fact that they present a line of least resistance for electricity to pass from a rain cloud into the ground might prove a serious menace to the structures upon which they are placed because of the enormous voltage they might be required to carry.

HEATING COILS FOR FUEL OIL STORAGE TANKS

Let F = Number square feet of heating surface required per barrel.
W = Weight of oil per barrel.
s = Specific heat of oil.
t = Required difference in temperature.
h = Number hours desired to obtain given temperature.
B = Number of B. T. U. transmitted per square foot per hour at 100 pounds steam pressure.

Then $F = \frac{Wst}{Bh}$

Constants are:
W = 343 lbs. per barrel, 12° Baume oil.
s = 0.498
B = 1170 (Johns-Manville Tests quoted in Marks)

Then

$$F = \frac{343x.498xt}{1170 \times h}$$

$$F = .146 \times \frac{t}{h}$$

Hence the number of feet of heating coils depends upon the range of temperature necessary and the time in which the change of temperature must be made.

Based upon this formula, the amount of heating surface to be placed in a given tank should be governed by the following considerations. As the end of the suction pipe should always be placed close to the bottom of the tank, it is necessary to provide coils sufficient to heat only that part of the volume near the bot-

tom, say the first 12 inches. Then the shape of the tank will determine the amount of coils to be placed.

For example, in a standard 55,000 barrel cylindrical tank 30 feet high, coils must be placed for approximately 1800 barrels. A 30,000 barrel rectangular concrete tank 12 feet deep will require heating surface for 2500 barrels.

As the amount of pipe placed is directly proportioned to the time in which the raise of temperature is required, it would be found economical in large tanks to place a separate coil very near to the end of the suction pipe, of sufficient area to heat a small amount of oil very rapidly, the balance of coils provided upon a basis of such longer time sufficient to heat the whole volume.

Consider the 30,000 barrel tank mentioned above, 500 feet of 2-inch pipe placed as a "suction coil," would raise the temperature of 30 barrels of oil 80 degrees in one hour's time

$$F = \frac{.146t}{h}$$

Allowing 10 hours to the 2500 barrels in the first 12 incnes of this tank.

$$F = \frac{.146 \times 80 \times 2500}{10} = 2920 \text{ sq. ft.}$$

If 2-inch pipe were used, 4670 feet would have to be placed as main coils. It would be advisable to separate these later into two units, with individual intake and discharge connections.

CHAPTER VIII.

TABLES AND USEFUL INFORMATION

MEASUREMENT OF FLOW OF NATURAL GAS WELLS[1]

Using the pilot tube.—The most accurate way of testing the flow of a gas well is by means of the pitot tube. This is an instrument for determining the velocity of flowing gas by means of its momentum. It usually consists of a small tube, one end bent at right angles, which is inserted in the flowing gas, just inside the pipe or tubing and between one-third and one-fourth of the pipe's diameter from the outer edge. The plane of the opening in the tube is held at right angles to the flowing gas. At a convenient distance, varying from one to two feet, an in verted siphon or U-shaped gauge is attached to the other end, which is usually half filled with mercury or water. If the flow is over five pounds to the square inch a pressure gauge is required.

In small sized wells of not over 4,000,000 feet, a 12-inch U gauge with water can be used. In wells from 4,000,000 to 15,000,000 feet, use mercury in a 12-inch gauge, from 15,000,000 to 35,000,000 feet use a 50-pound spring gauge. Above 35,000,000 feet use a 100-pound spring gauge. These foregoing figures are all based on a 6-inch hole.

For convenience, a scale graduated from the center in inches and tenths is attached between the two limbs of the U-gauge. The distance above and below this center line at which the liquid stands in the gauge should be added, the object being to determine the exact distance between the high and the low side of the fluid in inches and tenths of inches.

The top of tubing should be free from fittings for a distance of ten feet below the mouth of the well where the test is made. The test should not be made in a collar or gate or at the mouth of any

[1]From Westcott's Handbook of Natural Gas.

fitting. The well should be blown off for at least three hours prior to making the test.

Having ascertained the velocity pressure of the gas flowing from the well in inches of water, inches of mercury or pounds per square inch, as outlined above, the corresponding flow is given in the following table. The quantities of gas stated in the table are based on 4-ounce pressure or 14.65 pounds per square inch absolute, 60 degrees Fahr., flowing temperature, 60 degrees Fahr., storage temperature, and 0.6 specific gravity (air being 1.00). If the specific gravity is other than 0.6 the flow should be multiplied by

$$\sqrt{\frac{0.6}{\text{sp. gr. of gas}}}$$

For flowing temperature above or below 60° F., deduct or add 1 per cent for each 10 degrees, respectively.

Pitot Tube Table for the Testing of Gas Wells

Discharge of gas of 0.6 specific gravity from gas well tubing of different sizes in twenty-four hours

(By F. H. Oliphant)

Pressure			Discharge in Cubic Feet			
Inches of water	Inches of Mercury	Lbs. sq. inch	1-inch Tubing	2-inch Tubing	3-inch Tubing	4-inch Tubing
.10			11,880	47,520	106,920	190,080
.20			17,136	68,544	154,224	274,176
.30			20,568	82,272	185,112	329.088
.40			23,520	94,080	211,680	376,320
.50			26,544	106,176	238,896	424,704
.60			29,112	116,448	262,008	465,792
.7			31,440	125,760	282,960	503,040
.8			33,624	134,496	302,616	537,984
.9			35,640	142,560	320,760	570,240
1.0			37,320	149,280	335,880	597,120
1.25			41,712	166,848	375,408	667,392
1.5			45,960	183,840	413,640	735,360
1.75	.12		49,680	198,720	447,120	794,880
2.0	.147		53,136	212,544	478,224	850,176
2.5	.184		59.400	237,600	534,600	950,400
3.0	.22	.108	65,088	260,352	585,792	1041,408
3.5	.257	.126	70,272	281,088	632,448	1124,352
4.0	.294	.144	75,120	300,480	676,080	1201,920
4.5	.331	.162	79,704	318,810	717,336	1275,264
5.0	.368	.18	84,000	336,000	756,000	1344,000
6.	.441	.216	92,016	368,060	828,144	1472,256
7.	.515	.252	99,360	397,440	894,240	1589,760
8.	.588	.288	106.272	425,088	956,448	1700,352
9.	.662	.324	112,656	450,624	1013,904	1802,496
10.	.736	.36	118,800	475,200	1069,200	1900,800
11.	.8	.396	125,160	500,640	1126,440	2002,560
12.	.88	.432	130,128	520,512	1171,152	2082,048
	1.02	.5	138,960	555,840	1250,840	2223,360
	1.52	.75	170,280	681,120	1532,520	2724,480
	2.03	1.00	196,680	786,720	1770,120	3146,880
	2.54	1.25	219,960	879,840	1979.640	3519,360

Inches of water	Pressure Inches of Mercury	Lbs. sq. inch	Discharge in Cubic Feet 1-inch Tubing	2-inch Tubing	3-inch Tubing	4-inch Tubing
	3.05	1.5	240,720	962,880	2166,480	3851,520
	3.56	1.75	259,920	1039,680	2339,280	4158,720
	4.07	2.00	272,640	1090,560	2453,760	4362,240
	4.57	2.25	294,600	1178,400	2651,400	4713,600
	5.08	2.50	310,800	1243,200	2797,200	4972,800
	5.59	2.75	321,000	1284,000	2889,000	5136,000
	6.10	3.	340,200	1360,800	3061,800	5443,200
	6.61	3.25	354,120	1416,480	3187,080	5665,920
	7.11	3.50	367,680	1470,720	3309,120	5882,880
	7.62	3.75	380,400	1521,600	3423,600	6086,400
	8.13	4.00	329,880	1571,520	3535,920	6286,080
	8.64	4.25	405,000	1620,000	3645,000	6480,000
	9.15	4.50	416,640	1666,560	3749,760	6666,240
	9.65	4.75	428,280	1713,120	3854,520	6852,480
	10.16	5.00	439,920	1759,680	3959,280	7038,720
	12.20	6.	476,040	1904,160	4284,360	7616,640
		7.	517,320	2069,280	4655,880	8277,120
		8.	542,400	2169,600	4881,600	8678,400
		9.	569,640	2278,650	5126,760	9114,240
		10.	595,560	2382,240	5360,040	9528,960
		11.	621,960	2487,840	5597,640	9951,360
		12.	642,600	2570,400	5783,400	10281,600
		13.	664,680	2658,720	5982,120	10634,880
		14.	683,880	2735,520	6154,920	10942,080
		15.	703.080	2812,320	6327,720	11249,280
		16.	721,080	2884,320	6489,720	11537,280
		17.	738,120	2952,480	6643,080	11809,920
		18.	753,960	3015,840	6785,640	12063,360
		20.	785,520	3142,080	7069,680	12568,320
		22.	803,280	3213,120	7229,520	12852,480
		25.	854,880	3419,520	7693,920	13678,080
		30.	910,680	3642,720	8196,120	14570,880
		35.	960,960	3843,840	8648,640	15375,360
		40.	1006,680	4026,720	9060,120	16106,880
		45.	1046,520	4186,080	9418,680	16744,320
		50.	1081,920	4327,680	9737,280	17310,720
		60.	1137,120	4548,480	10234,080	18193,920
		75.	1223,400	4893,600	11010,600	19574,400
		90.	1394,400	5217,600	11739,600	20870,400
		100.	1336,920	5347,680	12032,280	21390,720

Multipliers for pipe diameters other than given in the above tables. For any different sized pipe apply the multiplier to the figures given in the above table for "one inch tubing."

1½"= 2.25	5" =25	8" =64
2½"= 6.25	5⅝"=31.64	8¼"=68
4¼"=18	6" =36	9" =81
4⅝"=21.39	6¼"=39	10" =100
	6⅝"=43.9	12" =144

Minute Pressure of Gas Wells

Quickly shut gate or valve and note pressure at end of each minute. Usually pressure at end of first minute is used to approximate volume.

VOLUME IN DIFFERENT SIZED TUBING IN LENGTH OF 100 FEET

Diam. Inches	Cu. ft. in 100 ft.	Diam. inches	Cu. ft. in 100'	Diam. inches	Cu. ft in 100'
1	.55	5	13.64	6⅝	23.94
2	2.19	5 3-16	14.14	7¼	28.67
3	4.91	5¼	15.03	8	34.91
3¼	5.76	5⅝	17.26	8¼	37.12
4	8.73	6	19.63	9⅝	50.53
4¼	9.85	6¼	21.31	10	54.54

MUITIPLIERS FOR DIFFERENT PRESSURES FOR 1 MINUTE AND FOR 24 HOURS

Gauge Lbs.	Multipliers 1 Min.	Multipliers 24 Hrs.	Gauge Lbs.	Multipliers 1 Min.	Multipliers 24 Hrs.
1	1.07	15.40	110	8.64	124.40
2	1.14	16.40	120	9.33	134.40
3	1.21	17.40	130	10.02	144.40
4	1.28	18.40	140	10.72	154.40
5	1.37	19.0	150	11.41	164.40
6	1.42	20.40	160	12.10	174.40
7	1.49	21.40	170	12.80	184.40
8	1.56	22.40	180	13.49	194.40
9	1.63	23.40	190	14.18	204.40
10	1.68	24.40	200	14.89	214.40
11	1.76	25.40	210	15.58	224.40
12	1.83	26.40	220	16.27	234.40
13	1.90	27.40	230	16.97	244.40
14	1.97	28.40	240	17.66	254.40
15	2.09	29.40	250	18.35	264.40
16	2.11	30.40	260	19.05	274.40
17	2.18	31.40	270	19.74	284.40
18	2.25	32.40	280	20.43	294.40
19	2.32	33.40	290	21.13	304.40
20	2.38	34.40	300	21.83	314.40
21	2.45	35.40	310	22.53	324.40
22	2.52	36.40	320	23.22	334.40
23	2.59	37.40	330	23.91	344.40
24	2.66	38.40	340	24.60	354.40
25	2.73	39.40	350	25.30	364.40
26	2.80	40.40	360	25.99	374.40
27	2.87	41.40	370	26.68	384.40
28	2.94	42.40	380	27.38	394.40
29	3.01	43.40	390	28.08	404.40
30	3.08	44.40	400	28.78	414.40
40	3.77	54.40	410	29.47	424.40
50	4.46	64.40	420	30.16	434.40
60	5.16	74.40	430	30.86	444.40
70	5.85	84.40	440	31.55	454.40
80	6.54	94.40	450	32.24	464.40
90	7.23	104.40	460	32.94	474.40
100	7.94	114.40	470	33.63	484.40
			480	34.32	494.40
			490	35.02	504.40
			500	35.72	514.40
			510	36.41	524.40
			520	37.11	534.40
			530	37.80	544.40
			540	38.49	554.40
			550	39.18	564.40
			560	39.88	574.40
			570	40.57	584.40
			580	41.27	594.40
			590	41.97	604.40
			600	42.67	614.40

EXAMPLE
MINUTE PRESSURE OF GAS WELLS

Suppose a well showed 320 lbs. gauge pressure in 1 minute in 2-inch tubing, depth of well being 1250 feet

320 = 23.22
2-in. = 2.19
1250 = 12.5 x 100
Cubic Ft. per Min. = 23.22x2.19x12.5
= 635.65
Cubic Ft. per Min. = 38,139
Cubic Ft. per Day = 24x38, 139=915,366

QUANTITY OF GAS, SIZE OF FEED, PIPES, ETC., REQUIRED FOR GAS ENGINES

Approximate discharge of gas of .6 gravity in 1-inch straight pipe, for various lengths in cubic feet per hour, at pressure of 4 oz. = 6.9" water at intake and 3.7 oz. = 6.4" water at discharge end.

Length of Pipe (ft.)	Cu. Ft. Hr.	Length Pipe (Feet)	Cu. Ft. Per Hr.
50	350	1100	73
100	247	1200	71
150	203	1300	68
200	175	1400	66
250	152	1500	64
300	143	1600	62
350	136	1800	58
400	124	2000	55

Length of Pipe (ft.)	Cu. Ft. Hr.	Length Pipe (Feet)	Cu. Ft. Per Hr.
450	115	2500	50
500	110	3000	47
600	102	3500	42
700	95	4000	40
800	88	4500	37
900	83	5000	35
1000	76	5280	34

MULTIPLIERS FOR DIAMETERS OTHER THAN ONE INCH

Size Pipe, Inches	½	1	1¼	1½	2	2½	3
Multipliers	.81	1.00	1.80	2.93	5.92	10.60	16.50

Pipe Size	4	5	6	8	10	12	15
Multipliers	34.10	60.0	95.0	198.	350.	556.	863.

COMPARISON OF FUEL PER H. P. PER HOUR FOR GAS, GASOLINE AND STEAM ENGINES

	Gas at 25c per M.		Gasoline at 15c per gal.		Coal at $1.50 Per Ton	
	Cu. ft.	Cost, cts.	Gals.	Cost, cts	Lbs.	Cost, cts.
Com. Gas Engine	9	.225	1–12	1.25	...	...
Oil C Style Gas Engine	13	.325	1–10	1.50	...	...
Steam Engine Cut off	40	1.	....	...	4	.5
Steam Engine No Cut off	80	2.	....	...	8	1.
Oil C Style St. Engine	130	3.25	....	...	13	1.63

U. S. PETROLEUM STANDARD BAUME' (60 DEGREES) SPECIFIC GRAVITY AND POUNDS PER GALLON

Baume'	Specific Gravity	Lbs. in U. S. Gal.	Specific Gravity	Lbs. in U. S. Gal.	Baume'
10.0	1.000	8.33	1.000	8.33	10.0
11.0	.993	8.27	.995	8.29	10.7
12.0	.986	8.21	.990	8.25	11.4
13.0	.979	8.16	.985	8.21	12.1
14.0	.973	8.10	.980	8.16	12.9
15.0	.966	8.05	.975	8.12	13.6
16.0	.959	7.99	.970	8.08	14.3
17.0	.953	7.94	.965	8.04	15.1
18.0	.947	7.88	.960	8.00	15.9
19.0	.940	7.83	.955	7.96	16.6
20.0	.934	7.78	.950	7.91	17.4
21.0	.928	7.73	.945	7.87	18.2
22.0	.922	7.68	.940	7.83	19.0
23.0	.916	7.63	.935	7.79	19.8
24.0	.910	7.58	.930	7.75	20.6
25.0	.904	7.53	.925	7.71	21.4
26.0	.898	7.48	.920	7.66	22.3
27.0	.893	7.44	.915	7.62	23.1
28.0	.887	7.39	.910	7.58	24.0
29.0	.882	7.34	.905	7.54	24.8
30.0	.876	7.30	.900	7.50	25.7
31.0	.871	7.25	.895	7.46	26.6
32.0	.865	7.21	.890	7.41	27.4
33.0	.860	7.17	.885	7.37	28.3
34.0	.855	7.12	.880	7.33	29.3
35.0	.850	7.08	.875	7.29	30.2
36.0	.845	7.04	.870	7.25	31.1
37.0	.840	7.00	.865	7.21	32.0
38.0	.835	6.95	.860	7.16	33.0
39.0	.830	6.91	.855	7.12	34.0
40.0	.825	6.87	.850	7.08	34.9
41.0	.820	6.83	.845	7.04	35.9

Baume'	Specific Gravity	Lbs. in U. S. Gal.	Specific Gravity	Lbs. in U. S. Gal.	Baume'
42.0	.816	6.79	.840	7.00	36.9
43.0	.811	6.76	.835	6.96	37.9
44.0	.806	6.72	.830	6.91	38.9
45.0	.802	6.68	.825	6.87	40.0
46.0	.797	6.64	.820	6.83	41.0
47.0	.793	6.60	.815	6.79	42.1
48.0	.788	6.57	.810	6.75	43.2
49.0	.784	6.53	.805	6.71	44.2
50.0	.780	6.49	.800	6.66	45.3
51.0	.775	6.46	.795	6.62	46.4
52.0	.771	6.42	.790	6.58	47.6
53.0	.767	6.39	.785	6.54	48.7
54.0	.763	6.35	.780	6.50	49.9
55.0	.759	6.32	.775	6.46	51.0
56.0	.755	6.29	.770	6.41	52.2
57.0	.751	6.25	.765	6.37	53.4
58.0	.747	6.22	.760	6.33	54.6
59.0	.743	6.19	.755	6.29	55.9
60.0	.739	6.16	.750	6.25	57.1
61.0	.735	6.12	.745	6.21	58.4
62.0	.731	6.09	.740	6.16	59.7
63.0	.728	6.06	.735	6.12	61.0
64.0	.724	6.03	.730	6.08	62.3
65.0	.720	6.00	.725	6.04	63.6
66.0	.717	5.97	.720	6.00	65.0
67.0	.713	5.94	.715	5.96	66.4
68.0	.709	5.91	.710	5.91	67.8
69.0	.706	5.88	.705	5.87	69.2
70.0	.702	5.85	.700	5.83	70.6
71.0	.699	5.82	.695	5.79	72.1
72.0	.695	5.79	.690	5.75	73.5
73.0	.692	5.76	.685	5.71	75.0
74.0	.689	5.74	.680	5.66	76.6
75.0	.685	5.71	.675	5.62	78.1
76.0	.682	5.68	.670	5.58	79.7
77.0	.679	5.65	.665	5.54	81.2
78.0	.675	5.63	.660	5.50	82.9
79.0	.672	5.60	.655	5.46	84.5
80.0	.669	5.57	.650	5.41	86.2
81.0	.666	5.55	.645	5.37	87.8
82.0	.663	5.52	.640	5.33	89.6
83.0	.660	5.50			
84.0	.657	5.47			
85.0	.654	5.44			
86.0	.651	5.42			
87.0	.648	5.39			
88.0	.645	5.37			
89.0	.642	5.35			
90.0	.639	5.32			

TEMPERATURE CORRECTIONS FOR DETERMINATION OF TRUE BAUME' GRAVITY

Explanation—These tables show the degrees Baume at 60° F. of oils having, at the designated temperatures, the observed degrees Baume' indicated. For example, if the degrees Baume' is 20.0 at 78° F., the true degrees Baume' at 60° F. will be 19.0. Intermediate values not given in the table may be conveniently interpolated. The headings "Observed degrees Baume," and "Observed temperature" indicate the actual reading of the hydrometer and the true temperature of the oil.

Observed temperature °F	Observed Degrees Baume 10.0	11.0	12.0	13.0	14.0	15.0	16.0	17.0	18.0	19.0
	Corresponding Degrees Baume at 60° F.									
60	10.0	11.0	12.0	13.0	14.0	15.0	16.0	17.0	18.0	19.0
62	9.9	10.9	11.9	12.9	13.9	14.9	15.9	16.9	17.9	18.9
64	9.8	10.8	11.8	12.8	13.8	14.8	15.8	16.8	17.8	18.8
66	9.7	10.7	11.7	12.7	13.7	14.7	15.7	16.7	17.7	18.7
68	9.6	10.6	11.6	12.6	13.6	14.6	15.6	16.6	17.6	18.6
70	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.4
72	9.4	10.4	11.4	12.4	13.4	14.4	15.4	16.4	17.3	18.3
74	9.3	10.3	11.3	12.3	13.3	14.3	15.3	16.2	17.2	18.2
76	9.2	10.2	11.2	12.2	13.2	14.2	15.2	16.1	17.1	18.1
78	9.1	10.1	11.1	12.1	13.1	14.1	15.1	16.0	17.0	18.0
80	9.1	10.0	11.0	12.0	13.0	14.0	14.9	15.9	16.9	17.9
82	9.0	9.9	10.9	11.9	12.9	13.9	14.8	15.8	16.8	17.8
84	8.9	9.8	10.8	11.8	12.8	13.8	14.7	15.7	16.7	17.7
86	8.8	9.8	10.7	11.7	12.7	13.7	14.6	15.6	16.6	17.6
88	8.7	9.7	10.6	11.6	12.6	13.6	14.5	15.5	16.5	17.4
90	8.6	9.6	10.5	11.5	12.5	13.5	14.4	15.4	16.4	17.3
92	8.5	9.5	10.4	11.4	12.4	13.4	14.3	15.3	16.2	17.2
94	8.4	9.4	10.3	11.3	12.3	13.2	14.2	15.2	16.1	17.1
96	8.3	9.3	10.2	11.2	12.2	13.1	14.1	15.1	16.0	17.0
98	8.2	9.2	10.1	11.1	12.1	13.0	14.0	15.0	15.9	16.9
100	8.1	9.1	10.0	11.0	12.0	12.9	13.9	14.9	15.8	16.8
102	8.0	9.0	9.9	10.9	11.9	12.8	13.8	14.8	15.7	16.7
104	7.9	8.9	9.8	10.8	11.8	12.7	13.7	14.7	15.6	16.6
106	7.8	8.8	9.7	10.7	11.7	12.6	13.6	14.6	15.5	16.5
108	7.7	8.7	9.6	10.6	11.6	12.5	13.5	14.5	15.4	16.4
110	7.6	8.6	9.5	10.5	11.5	12.4	13.4	14.4	15.3	16.3
112	7.5	8.5	9.4	10.4	11.4	12.3	13.3	14.3	15.2	16.2
114	7.4	8.4	9.3	10..3	11.3	12.2	13.2	14.1	15.1	16.1
116	7.3	8.3	9.2	10.2	11.2	12.1	13.1	14.0	15.0	16.0
118	7.2	8.2	9.1	10.1	11.1	12.0	13.0	13.9	14.9	15.9
120	7.1	8.1	9.0	10.0	11.0	11.9	12.9	13.8	14.8	15.8
122	7.0	8.0	8.9	9.9	10.9	11.8	12.8	13.7	14.7	15.6
124	6.9	7.9	8.8	9.8	10.8	11.7	12.7	13.6	14.6	15.5
126	6.8	7.8	8.7	9.7	10.7	11.6	12.6	13.5	14.5	15.4
128			8.6	9.6	10.6	11.5	12.5	13.4	14.4	15.3
130			8.5	9.5	10.5	11.4	12.4	13.3	14.3	15.2
132			8.5	9.4	10.4	11.3	12.3	13.2	14.2	15.1
134				9.3	10.3	11.2	12.2	13.1	14.1	15.0
136				9.2	10.2	11.1	12.1	13.0	14.0	14.9
138				9.1	10.1	11.0	12.0	12.9	13.9	14.8
140				9.1	10.0	10.9	11.9	12.8	13.8	14.7
142				9.0	9.9	10.8	11.8	12.7	13.7	14.6
144				8.9	9.8	10.7	11.7	12.6	13.6	14.5
146				8.8	9.7	10.6	11.6	12.5	13.5	14.4
148				8.7	9.6	10.5	11.5	12.4	13.4	14.3
150				8.6	9.5	10.4	11.4	12.3	13.3	14.2

Observed temperature in ° F	Observed degrees Baume									
	17.0	18.0	19.0	20.0	21.0	22.0	23.0	24.0	25.0	26.0
	Corresponding degrees Baume at 60° F									
30	18.6	19.7	20.7	21.7	22.7	23.7	24.8	25.8	26.9	27.9
32	18.6	19.6	20.6	21.6	22.6	23.6	24.7	25.7	26.8	27.8
34	18.5	19.5	20.5	21.5	22.5	23.5	24.6	25.6	26.7	27.7
36	18.3	19.4	20.4	21.4	22.4	23.4	24.5	25.5	26.5	27.5
38	18.2	19.3	20.3	21.3	22.3	23.3	24.4	25.4	26.4	27.4
40	18.1	19.1	20.1	21.2	22.2	23.2	24.2	25.2	26.2	27.2
42	18.0	19.0	20.0	21.1	22.1	23.1	24.1	25.1	26.1	27.1
44	17.9	18.9	19.9	20.9	21.9	22.9	23.9	24.9	26.0	27.0
46	17.8	18.8	19.8	20.8	21.8	22.8	23.8	24.8	25.9	26.9
48	17.6	18.7	19.7	20.7	21.7	22.7	23.7	24.7	25.8	26.8
50	17.5	18.6	19.6	20.6	21.6	22.6	23.6	24.6	25.6	26.6
52	17.4	18.5	19.5	20.5	21.5	22.5	23.5	24.5	25.5	26.5
54	17.3	18.3	19.3	20.3	21.3	22.3	23.3	24.3	25.4	26.4
56	17.2	18.2	19.2	20.2	21.2	22.2	23.2	24.2	25.3	26.3
58	17.1	18.1	19.1	20.1	21.1	22.1	23.1	24.1	25.1	26.1
60				20.0	21.0	22.0	23.0	24.0	25.0	26.0
62				19.9	20.9	21.9	22.9	23.9	24.9	25.9
64				19.8	20.8	21.8	22.8	23.8	24.7	25.7
66				19.7	20.7	21.7	22.7	23.7	24.6	25.6
68				19.5	20.5	21.5	22.5	23.5	24.5	25.5
70				19.4	20.4	21.4	22.4	23.4	24.4	25.4
72				19.3	20.3	21.3	22.3	23.3	24.3	25.3
74				19.2	20.2	21.2	22.2	23.2	24.1	25.1
76				19.1	20.1	21.1	22.1	23.1	24.0	25.0
78				19.0	19.9	20.9	21.9	22.9	23.9	24.9
80				18.9	19.8	20.8	21.8	22.8	23.8	24.8
82				18.8	19.7	20.7	21.7	22.7	23.7	24.7
84				18.7	19.6	20.6	21.6	22.6	23.5	24.5
86				18.6	19.5	20.5	21.5	22.5	23.4	24.4
88				18.4	19.4	20.4	21.3	22.3	23.3	24.3
90				18.3	19.3	20.3	21.2	22.2	23.2	24.2
92				18.2	19.2	20.2	21.1	22.1	23.1	24.1
94				18.1	19.1	20.1	21.0	22.0	23.0	24.0
96				18.0	19.0	20.0	20.9	21.9	22.8	23.8
98				17.9	18.8	19.8	20.8	21.8	22.7	23.7
100				17.8	18.7	19.7	20.7	21.7	22.6	23.6
102				17.7	18.6	19.6	20.5	21.5	22.5	23.5
104				17.6	18.5	19.5	20.4	21.4	22.4	23.4
106				17.5	18.4	19.4	20.3	21.3	22.3	23.3
108				17.3	18.2	19.2	20.2	21.2	22.2	23.1
110				17.2	18.1	19.1	20.1	21.1	22.0	23.0
112				17.1	18.0	19.0	20.0	21.0	21.9	22.9
114				17.0	17.9	18.9	19.9	20.9	21.8	22.8
116				16.9	17.8	18.8	19.8	20.8	21.7	22.7
118				16.8	17.7	18.7	19.6	20.6	21.5	22.5
120				16.7	17.6	18.6	19.5	20.5	21.4	22.4

Observed temperature in ° F	Observed degrees Baume									
	27.0	28.0	29.0	30.0	31.0	32.0	33.0	34.0	35.0	36.0
	Corresponding degrees Baume at 60° F									
30	29.0	30.0	31.0	32.0	33.1	34.1	35.2	36.2	37.3	38.3
32	28.8	29.8	30.9	31.9	33.0	34.0	35.0	36.0	37.1	38.1
34	28.7	29.7	30.8	31.8	32.8	33.8	34.8	35.8	36.9	38.0
36	28.5	29.5	30.6	31.6	32.7	33.7	34.7	35.7	36.8	37.8
38	28.4	29.4	30.5	31.5	32.5	33.5	34.5	35.5	36.6	37.7
40	28.3	29.3	30.4	31.4	32.4	33.4	34.4	35.4	36.5	37.5
42	28.2	29.2	30.2	31.2	32.2	33.2	34.3	35.3	36.3	37.3
44	28.1	29.1	30.1	31.1	32.1	33.1	34.2	35.2	36.2	37.2
46	27.9	28.9	29.9	30.9	31.9	32.9	34.0	35.0	36.1	37.1
48	27.8	28.8	29.8	30.8	31.8	32.8	33.9	34.9	35.9	36.9
50	27.6	28.6	29.7	30.7	31.7	32.7	33.7	34.7	35.7	36.7
52	27.5	28.5	29.6	30.6	31.6	32.6	33.6	34.6	35.6	36.6
54	27.4	28.4	29.4	30.4	31.4	32.4	33.4	34.4	35.4	36.4
56	27.3	28.3	29.3	30.3	31.3	32.3	33.3	34.3	35.3	36.3
58	27.1	28.1	29.1	30.1	31.1	32.1	33.1	34.1	35.1	36.1
60	27.0	28.0	29.0	30.0	31.0	32.0	33.0	34.0	35.0	36.0
62	26.9	27.9	28.9	29.9	30.9	31.9	32.9	33.9	34.9	35.9
64	26.7	27.7	28.7	29.7	30.7	31.7	32.7	33.7	34.7	35.7
66	26.6	27.6	28.6	29.6	30.6	31.6	32.6	33.6	34.6	35.6
68	26.5	27.5	28.4	29.4	30.4	31.4	32.4	33.4	34.4	35.4
70	26.4	27.4	28.3	29.3	30.3	31.3	32.2	33.2	34.2	35.2
72	26.3	27.3	28.2	29.2	30.2	31.2	32.1	33.1	34.1	35.1
74	26.1	27.1	28.1	29.1	30.1	31.1	32.0	33.0	33.9	34.9
76	26.0	27.0	27.9	28.9	29.9	30.9	31.8	32.8	33.8	34.8
78	25.8	26.8	27.8	28.8	29.8	30.8	31.7	32.7	33.6	34.6
80	25.7	26.7	27.7	28.7	29.7	30.7	31.6	32.6	33.5	34.5
82	25.6	26.6	27.6	28.6	29.5	30.5	31.5	32.5	33.4	34.4
84	25.5	26.5	27.5	28.5	29.4	30.4	31.3	32.3	33.2	34.2
86	25.4	26.4	27.3	28.3	29.2	30.2	31.2	32.2	33.1	34.1
88	25.2	26.2	27.2	28.2	29.1	30.1	31.0	32.0	33.0	34.0
90	25.1	26.1	27.0	28.0	29.0	30.0	30.9	31.9	32.9	33.9
92	25.0	26.0	26.9	27.9	28.9	29.9	30.8	31.8	32.7	33.7
94	24.9	25.9	26.8	27.8	28.8	29.8	30.7	31.7	32.6	33.6
96	24.7	25.7	26.7	27.7	28.6	29.6	30.5	31.5	32.5	33.5
96	24.6	25.6	26.6	27.6	28.5	29.5	30.4	31.4	32.3	33.3
100	24.5	25.5	26.4	27.4	28.3	29.3	30.3	31.3	32.2	33.2
102	24.4	25.4	26.3	27.3	28.2	29.2	30.2	31.2	32.1	33.0
104	24.3	25.3	26.2	27.1	28.1	29.1	30.0	31.0	31.9	32.9
106	24.2	25.2	26.1	27.0	28.0	29.0	29.9	30.9	31.8	32.7
108	24.0	25.0	25.9	26.9	27.8	28.8	29.7	30.7	31.6	32.6
110	23.9	24.9	25.8	26.8	27.7	28.7	29.6	30.6	31.5	32.5
112	23.8	24.8	25.7	26.7	27.6	28.6	29.5	30.4	31.3	32.3
114	23.7	24.7	25.6	26.6	27.5	28.4	29.3	30.3	31.2	32.2
116	23.6	24.6	25.5	26.4	27.3	28.3	29.2	30.2	31.1	32.1
118	23.4	24.4	25.3	26.3	27.2	28.2	29.1	30.1	31.0	32.0
120	23.3	24.3	25.2	26.2	27.1	28.1	29.0	30.0	30.9	31.9

Observed temperature in ° F	Observed degrees Baume									
	37.0	38.0	39.0	40.0	41.0	42.0	43.0	44.0	45.0	46.0
	Corresponding degrees Baume at 60° F									
30	39.3	40.3	41.4	42.4	43.5	44.5	45.6	46.6	47.7	48.7
32	39.2	40.2	41.3	42.3	43.4	44.3	45.4	46.4	47.5	48.5
34	39.0	40.0	41.1	42.1	43.2	44.2	45.3	46.3	47.3	48.3
36	38.9	39.9	41.0	42.0	43.1	44.0	45.1	46.1	47.2	48.2
38	38.7	39.7	40.8	41.8	42.9	43.9	45.0	46.0	47.0	48.0
40	38.5	39.5	40.6	41.6	42.7	43.7	44.8	45.8	46.8	47.8
42	38.4	39.4	40.5	41.5	42.5	43.5	44.6	45.6	46.6	47.6
44	38.2	39.2	40.3	41.3	42.4	43.4	44.4	45.4	46.4	47.4
46	38.1	39.1	40.1	41.1	42.2	43.2	44.2	45.2	46.2	47.2
48	37.9	38.9	39.9	40.9	42.0	43.0	44.1	45.1	46.1	47.1
50	37.8	38.8	39.8	40.8	41.8	42.8	43.9	44.9	45.9	46.9
52	37.6	38.6	39.6	40.7	41.7	42.7	43.7	44.7	45.7	46.7
54	37.4	38.4	39.5	40.5	41.5	42.5	43.5	44.5	45.5	46.5
56	37.3	38.3	39.3	40.3	41.3	42.3	43.3	44.3	45.3	46.3
58	37.1	38.1	39.1	40.1	41.1	42.1	43.1	44.1	45.2	46.2
60	37.0	38.0	39.0	40.0	41.0	42.0	43.0	44.0	45.0	46.0
62	36.9	37.9	38.9	39.9	40.9	41.9	42.9	43.9	44.9	45.9
64	36.7	37.7	38.7	39.7	40.7	41.7	52.7	43.7	44.7	45.7
66	36.6	37.6	38.6	39.5	40.5	41.5	42.5	43.5	44.5	45.5
68	36.4	37.4	38.4	39.4	40.4	41.4	42.4	43.3	44.3	45.3
70	36.2	37.2	38.2	39.2	40.2	41.2	42.2	43.1	44.1	45.1
72	36.1	37.1	38.1	39.1	40.0	41.0	42.0	43.0	44.0	45.0
74	35.9	36.9	37.9	38.9	39.8	40.8	41.8	52.8	53.8	44.8
76	35.8	36.8	37.8	38.7	39.7	40.7	41.7	42.7	43.6	44.6
78	35.6	36.6	37.6	38.6	39.5	40.5	41.5	42.5	43.4	44.4
80	35.5	36.5	37.5	38.5	39.4	40.4	41.3	42.3	43.2	44.2
82	35.3	36.3	37.3	38.3	39.2	40.2	41.2	42.2	43.1	44.1
84	35.2	36.2	37.2	38.2	39.1	40.1	41.0	42.0	42.9	43.9
86	35.1	36.1	37.0	38.0	38.9	39.9	40.9	41.9	42.8	43.8
88	34.9	35.9	36.9	37.9	38.8	39.8	40.7	41.7	42.6	43.6
90	34.8	35.8	36.7	37.7	38.6	39.6	40.5	41.5	42.5	43.5
92	34.6	35.6	36.6	37.6	38.5	39.5	40.4	41.4	42.3	43.3
94	34.5	35.5	36.4	37.4	38.3	39.3	40.2	41.2	42.2	43.2
96	34.4	35.4	36.3	37.3	38.2	39.2	40.1	41.1	42.0	43.0
98	34.2	35.2	36.1	37.1	38.0	39.0	39.9	40.9	41.8	42.8
100	34.1	35.1	36.0	37.0	37.9	38.9	39.8	40.7	41.6	42.6
102	33.9	34.9	35.8	36.8	37.7	38.7	39.6	40.6	41.5	42.5
104	33.8	34.8	35.7	36.7	37.6	38.6	39.5	40.4	41.3	42.3
106	33.6	34.6	35.5	36.5	37.4	38.4	39.3	40.3	41.2	42.2
108	33.5	34.5	36.4	36.4	37.3	38.3	39.2	40.1	41.0	42.0
110	33.4	34.4	35.3	36.3	37.2	38.1	39.0	40.0	40.9	41.8
112	33.2	34.2	35.1	36.1	37.0	38.0	38.9	39.8	40.7	41.6
114	33.1	34.1	35.0	36.0	36.9	37.8	38.7	39.7	40.6	41.5
116	33.0	34.0	34.9	35.9	36.8	37.7	38.6	39.5	40.4	41.4
118	32.9	33.9	34.8	35.7	36.6	37.5	38.4	39.4	40.3	41.2
120	32.8	33.7	34.6	35.6	36.5	37.4	38.3	39.2	40.1	41.0

Observed temperature in °F	Observed degrees Baume									
	47.0	48.0	49.0	50.0	51.0	52.0	53.0	54.0	55.0	56.0
	Corresponding degrees Baume at 60° F									
30	49.8	50.8	51.9	53.0	54.1	55.1	56.2	57.3	58.4	59.4
32	49.6	50.6	51.7	52.8	53.9	54.9	56.0	57.1	58.2	59.2
34	49.4	50.4	51.5	52.6	53.7	54.7	55.8	56.8	57.9	58.9
36	49.3	50.3	51.4	52.4	53.5	54.5	55.6	56.6	57.7	58.7
38	49.1	50.1	51.2	52.2	53.3	54.3	55.4	56.4	57.5	58.5
40	48.9	49.9	51.0	52.0	53.0	54.1	55.2	56.2	57.2	58.2
42	48.7	49.7	50.8	51.8	52.8	53.8	54.9	56.0	57.0	58.0
44	48.5	49.5	50.6	51.6	52.6	53.6	54.7	55.7	56.8	57.8
46	48.3	49.3	50.4	51.4	52.4	53.4	54.5	55.5	56.5	57.5
48	48.1	49.1	50.2	51.2	52.2	53.2	54.2	55.2	56.3	57.3
50	47.9	48.9	50.0	51.0	52.0	53.0	54.0	55.0	56.1	57.1
52	47.7	48.7	49.8	50.8	51.8	52.8	53.8	54.8	55.9	56.9
54	47.6	48.6	49.6	50.6	51.6	52.6	53.6	54.6	55.6	56.6
56	47.4	48.4	49.4	50.4	51.4	52.4	53.4	54.4	55.4	56.4
58	47.2	48.2	49.2	50.2	51.2	52.2	53.2	54.2	55.2	56.2
60	47.0	48.0	49.0	50.0	51.0	52.0	53.0	54.0	55.0	56.0
62	46.9	47.9	48.8	49.8	50.8	51.8	52.8	53.8	54.8	55.8
64	46.7	47.7	48.6	49.6	50.6	51.6	52.6	53.6	54.6	55.6
66	46.5	47.5	48.4	49.4	50.4	51.4	52.4	53.4	54.4	55.4
68	46.3	47.3	48.3	49.3	50.3	51.3	52.2	43.2	54.2	55.2
70	46.1	47.1	48.1	49.1	50.1	51.1	52.0	53.0	54.0	55.0
72	46.0	47.0	47.9	48.9	49.9	50.9	51.8	52.8	53.8	54.8
74	45.8	46.8	47.7	48.7	49.7	50.7	51.6	52.6	53.5	54.5
76	45.6	46.6	47.5	48.5	49.5	50.5	51.4	52.4	53.3	54.3
78	45.4	46.4	47.3	48.3	49.3	50.3	51.2	52.2	53.1	54.1
80	45.2	46.2	47.2	48.2	49.1	50.1	51.0	52.0	52.9	53.9
82	45.1	46.1	47.0	48.0	48.9	49.9	50.8	51.8	52.7	53.7
84	44.9	45.9	46.8	47.8	48.7	49.7	50.6	51.6	52.5	53.5
86	44.7	45.7	46.6	47.6	48.5	49.5	50.4	51.4	52.3	53.3
88	44.5	45.5	46.4	47.4	48.3	49.3	50.2	51.2	52.1	53.1
90	44.4	45.4	46.3	47.3	48.2	49.2	50.1	51.0	51.9	52.9
92	44.2	45.2	46.1	47.1	48.0	49.0	49.9	50.9	51.8	52.7
94	44.1	45.1	46.0	46.9	47.8	48.8	49.7	50.7	51.6	52.5
96	43.9	44.9	45.8	46.7	47.6	48.6	49.5	50.5	51.4	52.3
98	43.7	44.7	45.6	46.6	47.5	48.4	49.3	50.3	51.2	52.1
100	43.5	44.5	45.4	46.4	47.3	48.3	49.2	50.1	51.0	51.9
102	43.4	44.3	45.2	46.2	47.1	48.1	49.0	49.9	50.8	51.7
104	43.2	44.1	45.0	46.0	46.9	47.9	48.8	59.7	50.6	51.5
106	43.1	44.0	44.9	45.8	46.7	47.7	48.6	49.5	50.4	51.3
108	42.9	43.9	44.8	45.7	46.6	47.5	48.4	49.4	50.3	51.2
110	42.7	43.7	44.6	45.6	46.5	47.4	48.3	49.2	50.1	51.0
112	42.5	43.5	44.4	45.4	46.3	47.2	48.1	49.0	49.9	50.8
114	42.4	43.4	44.3	45.3	46.2	47.1	48.0	48.8	49.7	50.6
116	42.3	43.3	44.2	45.1	46.0	46.9	47.8	48.6	49.5	50.4
118	42.1	43.1	44.0	44.9	45.8	46.7	47.6	48.4	49.3	50.2
120	41.9	42.9	43.8	44.7	45.6	46.5	47.4	48.2	49.1	50.0

Observed temperature in ° F	Observed degrees Baume									
	57.0	58.0	59.0	60.0	61.0	62.0	63.0	64.0	65.0	66.0
	Corresponding degrees Baume at 60° F									
30	60.5	61.6	62.7	63.7	64.8	65.8	66.9	67.9	69.0	70.0
32	60.3	61.3	62.4	63.4	64.5	65.5	66.6	67.7	68.8	69.8
34	60.0	61.0	62.1	63.1	64.2	65.2	66.3	67.4	68.5	69.5
36	59.8	60.8	61.9	62.9	64.0	65.0	66.1	67.1	68.2	69.2
38	59.5	60.5	61.6	62.6	63.7	64.7	65.8	66.8	67.9	68.9
40	59.3	60.3	61.4	62.4	63.5	64.5	65.5	66.5	67.6	68.6
42	59.1	60.1	61.2	62.2	63.3	64.3	65.3	66.3	67.4	68.4
44	58.9	59.9	61.0	62.0	63.0	64.0	65.0	66.0	67.1	68.1
46	58.6	59.6	60.7	61.7	62.7	63.7	64.8	65.8	66.8	67.8
48	58.4	59.4	60.4	61.4	62.5	63.5	64.5	65.5	66.5	67.5
50	58.1	59.1	60.2	61.2	62.2	63.2	64.2	65.2	66.2	67.2
52	57.9	58.9	60.0	61.0	62.0	63.0	64.0	65.0	66.0	67.0
54	57.7	58.7	59.8	60.8	61.8	62.8	63.8	64.8	65.8	66.8
56	57.5	58.5	59.5	60.5	61.5	62.5	63.6	64.6	65.6	66.6
58	57.3	58.3	59.3	60.3	61.3	62.3	63.3	64.3	65.3	66.3
60	57.0	58.0	59.0	60.0	61.0	62.0	63.0	64.0	65.0	66.0
62	56.8	57.8	58.8	59.8	60.8	61.8	62.7	63.7	64.7	65.7
64	56.6	57.6	58.6	59.6	60.5	61.5	62.5	63.5	64.5	65.5
66	56.4	57.4	58.3	59.3	60.3	61.3	62.3	63.3	64.2	65.2
68	56.1	57.1	58.1	59.1	60.1	61.1	62.1	63.1	64.0	65.0
70	55.9	56.9	57.9	58.9	59.8	60.8	61.8	62.8	63.8	64.8
72	55.7	56.7	57.7	58.7	59.6	60.6	61.6	62.6	63.5	64.5
74	55.5	56.5	57.4	58.4	59.3	60.3	61.3	62.3	63.2	64.2
76	55.3	56.3	57.2	58.2	59.1	60.1	61.0	62.0	63.0	64.0
78	55.0	56.0	57.0	58.0	58.9	59.9	60.8	61.8	62.8	63.8
80	54.8	55.8	56.8	57.8	58.7	59.7	60.6	61.6	62.6	63.6
82	54.6	55.6	56.5	57.5	58.4	59.4	60.4	61.4	62.3	63.3
84	54.4	55.4	56.3	57.3	58.2	59.2	60.1	61.1	62.0	63.0
86	54.2	55.2	56.1	57.1	58.0	59.0	59.9	60.9	61.8	62.8
88	54.0	55.0	55.9	56.9	57.8	58.8	59.7	60.6	61.5	62.5
90	53.8	54.8	55.7	56.7	57.6	58.6	59.5	60.4	61.3	62.3
92	53.6	54.6	55.5	56.5	57.4	58.4	59.3	60.2	61.1	62.1
94	53.4	54.3	55.2	56.2	57.1	58.1	59.0	59.9	60.8	61.8
96	53.2	54.1	55.0	56.0	56.9	57.9	58.8	59.7	60.6	61.6
98	53.0	53.9	54.8	55.8	56.7	57.6	58.5	59.5	60.4	61.3
100	52.8	53.7	54.6	55.6	56.5	57.4	58.3	59.3	60.2	61.1
102	52.6	53.5	54.4	55.4	56.3	57.2	58.1	59.0	59.9	60.9
104	52.4	53.3	54.2	55.2	56.1	57.0	57.9	58.8	59.7	60.7
106	52.2	53.1	54.0	55.0	55.9	56.8	57.7	58.6	59.5	60.4
108	52.1	53.0	53.9	54.8	55.7	56.6	57.5	58.4	59.3	60.2
110	51.9	52.8	53.7	54.6	55.5	56.4	57.3	58.2	59.1	60.0
112	51.7	52.6	53.5	54.4	55.2	56.2	57.1	58.0	58.9	59.8
114	51.5	52.4	53.3	54.2	55.1	56.0	56.9	57.8	58.7	59.6
116	51.3	52.2	53.1	54.0	54.9	55.8	65.7	57.6	58.4	59.3
118	51.1	52.0	52.9	53.8	54.7	55.6	56.5	57.4	58.2	59.1
120	50.9	51.8	52.7	53.6	54.5	55.4	56.3	57.2	58.0	58.9

Observed temperature in ° F	67.0	68.0	69.0	70.0	71.0	72.0	73.0	74.0	75.0	76.0
	Observed degrees Baume									
	Corresponding degrees Baume at 60° F									
30	71.1	72.1	73.2	74.3	75.4	76.4	77.5	78.5	79.6	80.7
32	70.9	71.9	73.0	74.0	75.1	76.1	77.2	78.2	79.3	80.4
34	70.6	71.6	72.7	73.7	74.8	75.8	76.9	77.9	79.0	80.1
36	70.3	71.3	72.4	73.4	74.5	75.5	76.6	77.6	78.7	79.7
38	70.0	71.0	72.1	73.1	74.2	75.2	76.3	77.3	78.4	79.4
40	69.7	70.7	71.8	72.8	73.9	74.9	76.0	77.0	78.1	79.1
42	69.4	70.4	71.5	72.5	73.6	74.6	75.7	76.7	77.8	78.8
44	69.1	70.1	71.2	72.2	73.3	74.3	75.4	76.4	77.5	78.5
46	68.8	69.8	70.9	71.9	73.0	74.0	75.1	76.1	77.1	78.1
48	68.6	69.6	70.6	71.6	72.7	73.7	74.8	75.8	76.8	77.8
50	68.3	69.3	70.4	71.4	72.5	73.5	74.5	75.5	76.5	77.5
52	68.0	69.0	70.1	71.1	72.2	73.2	74.2	75.2	76.2	77.2
54	67.8	68.8	69.9	70.9	71.9	72.9	73.9	74.9	75.9	76.9
56	67.6	68.6	69.6	70.6	71.6	72.6	73.6	74.6	75.6	76.6
58	67.3	68.3	69.3	70.3	71.3	72.3	73.3	74.3	75.3	76.3
60	67.0	68.0	69.0	70.0	71.0	72.0	73.0	74.0	75.0	76.0
62	66.7	67.7	68.7	69.7	70.7	71.7	72.7	73.7	74.7	75.7
64	66.4	67.4	68.4	69.4	70.4	71.4	72.4	73.4	74.4	75.4
66	66.2	67.2	68.2	69.2	70.1	71.1	72.1	73.1	74.1	75.1
68	66.0	67.0	67.9	68.9	69.8	70.8	71.8	72.8	73.8	74.8
70	65.7	66.7	67.6	68.6	69.5	70.5	71.5	72.5	73.5	74.5
72	65.4	66.4	67.4	68.4	69.3	70.3	71.2	72.2	73.2	74.2
74	65.2	66.2	67.2	68.2	69.1	70.1	71.0	72.0	72.9	73.9
76	64.9	65.9	66.9	67.9	68.8	69.8	70.8	71.8	72.7	73.7
78	64.7	65.6	66.6	67.6	68.5	69.5	70.5	71.5	72.4	73.4
80	64.5	65.4	66.4	67.4	68.3	69.3	70.2	71.2	72.1	73.1
82	64.2	65.2	66.1	67.1	68.0	69.0	69.9	70.9	71.8	72.8
84	63.9	64.9	65.8	66.8	67.7	68.7	69.6	70.6	71.5	72.5
86	63.7	64.7	65.6	66.6	67.5	68.4	69.3	70.3	71.3	72.3
88	63.4	64.4	65.3	66.3	67.2	68.2	69.1	70.1	71.0	72.0
90	63.2	64.2	65.1	66.1	67.0	68.0	68.9	69.9	70.8	71.7
92	63.0	64.0	64.9	65.8	66.7	67.7	68.6	69.6	70.5	71.4
94	62.7	63.7	64.6	65.6	66.5	67.4	68.3	69.3	70.2	71.1
96	62.5	63.5	64.4	65.4	66.3	67.2	68.1	69.0	69.9	70.8
98	62.2	63.2	64.1	65.1	66.0	66.9	67.8	68.8	69.7	70.6
100	62.0	63.0	63.9	64.9	65.8	66.7	67.6	68.5	69.4	70.4
102	61.8	62.8	63.7	64.6	65.5	66.4	67.3	68.2	69.1	70.1
104	61.6	62.5	63.4	64.3	65.2	66.1	67.0	67.9	68.8	69.8
106	61.3	62.3	63.2	64.1	65.0	65.9	66.8	67.7	68.6	69.5
108	61.1	62.0	62.9	63.8	64.8	65.7	66.6	67.5	68.4	69.3
110	60.9	61.8	62.7	63.6	64.5	65.4	66.3	67.2	68.1	69.0
112	60.7	61.6	62.5	63.3	64.2	65.2	66.1	67.0	67.8	68.7
114	60.5	61.4	62.3	63.1	64.0	64.9	65.8	66.7	67.6	68.5
116	60.2	61.1	62.0	62.9	63.8	64.7	65.6	66.5	67.4	68.3
118	60.0	60.9	61.8	62.7	63.6	64.5	65.4	66.3	67.1	68.0
120	59.8	60.7	61.6	62.5	63.3	64.2	65.1	66.0	66.8	67.7

Observed temperature in ° F	Observed degrees Baume									
	77.0	78.0	79.0	80.0	81.0	82.0	83.0	84.0	85.0	86.0
	Corresponding degrees Baume at 60° F									
30	81.8	82.9	84.0	85.0	86.1	87.1	88.2	89.3	90.4	91.5
32	81.5	82.6	83.7	84.7	85.8	86.8	87.9	89.0	90.1	91.1
34	81.2	82.2	83.3	84.3	85.4	86.4	87.5	88.6	89.7	90.7
36	80.8	81.9	83.0	84.0	85.1	86.1	87.2	88.2	89.3	90.3
38	80.5	81.5	82.6	83.6	84.7	85.7	86.8	87.8	88.9	89.9
40	80.1	81.1	82.2	83.2	84.3	85.3	86.4	87.4	88.5	89.5
42	79.8	80.8	81.9	82.9	84.0	85.0	86.1	87.1	88.2	89.2
44	79.5	80.5	81.6	82.6	83.7	84.7	85.8	86.8	87.8	88.8
46	79.2	80.2	81.3	82.3	83.4	84.4	85.4	86.5	87.5	88.5
48	78.9	79.9	81.0	82.0	83.0	84.0	85.1	86.1	87.1	88.1
50	78.6	79.6	80.6	81.6	82.6	83.6	84.7	85.7	86.7	87.7
52	78.2	79.2	80.3	81.3	82.3	83.3	84.3	85.3	86.3	87.3
54	77.9	78.9	79.9	81.0	82.0	83.0	84.0	85.0	86.0	87.0
56	77.6	78.6	79.6	80.6	81.6	82.6	83.7	84.7	85.7	86.7
58	77.3	78.3	79.3	80.3	81.3	82.3	83.3	84.3	85.3	86.3
60	77.0	78.0	79.0	80.0	81.0	82.0	83.0	84.0	85.0	86.0
62	76.7	77.7	78.7	79.7	80.7	81.7	82.7	83.7	84.7	85.7
64	76.4	77.4	78.4	79.4	80.4	81.4	82.3	83.4	84.3	85.3
66	76.1	77.1	78.1	79.1	80.0	81.0	82.0	83.0	84.0	85.0
68	75.8	76.8	77.7	78.7	79.7	80.7	81.7	82.7	83.7	84.7
70	75.5	76.5	77.4	78.4	79.4	80.4	81.4	82.4	83.3	84.3
72	75.2	76.2	77.1	78.1	79.1	80.1	81.1	82.1	83.0	84.0
74	74.9	75.9	76.8	77.8	78.8	79.8	80.7	81.7	82.7	83.7
76	74.6	75.6	76.5	77.5	78.4	79.4	80.4	81.4	82.4	83.4
78	74.3	75.3	76.2	77.2	78.1	79.1	80.1	81.1	82.0	83.0
80	74.0	75.0	75.9	76.9	77.8	78.8	79.8	80.8	81.7	82.7
82	73.7	74.7	75.6	76.6	77.5	78.5	79.4	80.4	81.3	82.3
84	73.4	74.5	75.3	76.3	77.2	78.2	79.1	80.1	81.0	82.0
86	73.2	74.1	75.0	76.0	76.9	77.9	78.8	79.8	80.7	81.7
88	72.9	73.9	74.8	75.8	76.7	77.6	78.5	79.5	80.4	81.4
90	72.6	73.6	74.5	75.5	76.4	77.3	78.2	79.2	80.1	81.1
92	72.3	73.3	74.2	75.2	76.1	77.0	77.9	78.9	79.8	80.8
94	72.0	73.0	73.9	74.9	75.8	76.7	77.6	78.6	79.5	80.5
96	71.7	72.7	73.6	74.6	75.5	76.4	77.3	78.3	79.2	80.2
98	71.5	72.4	73.3	74.3	75.2	76.1	77.0	78.0	78.9	79.8
100	71.2	72.1	73.0	74.0	74.9	75.8	76.7	77.6	78.5	79.5
102	71.0	71.9	72.8	73.7	74.6	75.5	76.4	77.3	78.2	79.2
104	70.7	71.6	72.5	73.4	74.3	75.2	76.1	77.0	77.9	78.8
106	70.4	71.3	72.2	73.1	74.0	74.9	75.8	76.7	77.6	78.5
108	70.1	71.0	71.9	72.8	73.7	74.6	75.5	76.4	77.3	78.2
110	69.8	70.7	71.6	72.5	73.4	74.3	75.2	76.1	77.0	77.9
112	69.6	70.5	71.4	72.3	73.2	74.1	74.9	75.8	76.7	77.6
114	69.4	70.3	71.2	72.1	72.9	73.8	74.6	75.5	76.4	77.3
116	69.1	70.0	70.9	71.8	72.6	73.5	74.3	75.2	76.1	77.0
118	68.8	69.7	70.6	71.5	72.3	73.2	74.0	74.9	75.8	76.7
120	68.5	69.4	70.3	71.2	72.0	72.9	73.7	74.6	75.5	76.4

Observed temperature in °F	Observed degrees Baume									
	87.0	88.0	89.0	90.0	91.0	92.0	93.0	94.0	95.0	96.0
	Corresponding degrees Baume at 60° F									
30..............	92.6	93.6	94.7	95.7						
32..............	92.2	93.2	94.3	95.3						
34..............	91.8	92.9	93.9	94.9	95.9					
36..............	91.4	92.5	93.6	94.6	95.6					
38..............	91.0	92.1	93.2	94.2	95.2					
40..............	90.6	91.7	92.8	93.8	94.9	95.9				
42..............	90.3	91.3	92.4	93.4	94.5	95.5				
44..............	89.9	90.9	92.0	93.0	94.1	95.1	96.1			
46..............	89.6	90.6	91.7	92.7	93.7	94.7	95.7			
48..............	89.2	90.2	91.3	92.3	93.3	94.3	95.3			
50..............	88.8	89.8	90.9	91.9	92.9	93.9	94.9	95.9		
52..............	88.4	89.4	90.5	91.5	92.5	93.5	94.5	95.5		
54..............	88.0	89.0	90.1	91.1	92.1	93.1	94.1	95.1		
56..............	87.7	88.7	89.7	90.7	91.7	92.7	93.7	94.7	95.7	
58..............	87.3	88.3	89.4	90.4	91.4	92.4	93.4	94.4	95.4	
60..............	87.0	88.0	89.0	90.0	91.0	92.0	93.0	94.0	95.0	96.0
62..............	86.7	87.7	88.6	89.6	90.6	91.6	92.6	93.6	94.6	95.6
64..............	86.3	87.3	88.3	89.3	90.3	91.3	92.2	93.2	94.2	95.2
66..............	86.0	87.0	88.0	89.0	89.9	90.9	91.8	92.8	93.8	94.8
68..............	85.6	86.6	87.6	88.6	89.5	90.5	91.4	92.4	93.4	94.4
70..............	85.3	86.3	87.3	88.3	89.2	90.1	91.0	92.0	93.0	94.0
72..............	85.0	86.0	86.9	87.9	88.8	89.8	90.7	91.7	92.7	93.7
74..............	84.6	85.6	86.5	87.5	88.4	89.4	90.3	91.3	92.3	93.3
76..............	84.3	85.3	86.2	87.2	88.1	89.1	90.0	91.0	92.0	93.0
78..............	84.0	85.0	85.9	86.9	87.8	88.7	89.6	90.6	91.6	92.6
80..............	83.6	84.6	85.5	86.5	87.4	88.4	89.3	90.2	91.2	92.2
82..............	83.2	84.2	85.1	86.1	87.0	88.0	88.9	89.8	90.8	91.8
84..............	82.9	83.8	84.7	85.7	86.6	87.6	88.5	89.4	90.4	91.4
86..............	82.6	83.5	84.4	85.4	86.3	87.3	88.2	89.1	90.0	91.0
88..............	82.3	83.2	84.1	85.1	86.0	87.0	87.9	88.8	89.7	90.7
90..............	82.0	82.9	83.8	84.8	85.7	86.6	87.5	88.4	89.3	90.3
92..............	81.7	82.6	83.5	84.4	85.3	86.2	87.1	88.1	89.0	90.0
94..............	81.3	82.2	83.1	84.1	85.0	85.9	86.8	87.7	88.6	89.6
96..............	81.0	81.9	82.8	83.7	84.6	85.6	86.5	87.4	88.3	89.3
98..............	80.7	81.6	82.5	83.4	84.3	85.2	86.1	87.0	88.0	89.0
100..............	80.4	81.3	82.2	83.1	84.0	84.9	85.8	86.7	87.6	88.6
102..............	80.1	81.0	81.9	82.8	83.7	84.6	85.5	86.4	87.3	88.3
104..............	79.7	80.6	81.5	82.5	83.4	84.3	85.2	86.1	87.0	87.9
106..............	79.4	80.3	81.2	82.1	83.0	83.9	84.8	85.7	86.6	87.6
108..............	79.1	80.0	80.9	81.8	82.7	83.6	84.5	85.4	86.3	87.2
110..............	78.8	79.7	80.6	81.5	82.4	83.3	84.2	85.1	86.0	86.9
112..............	78.5	79.4	80.3	81.2	82.1	83.0	83.8	84.7	85.6	86.6
114..............	78.2	79.1	80.0	80.9	81.7	82.6	83.5	84.4	85.3	86.2
116..............	77.9	78.8	79.7	80.6	81.4	82.3	83.2	84.1	85.0	85.9
118..............	77.5	78.4	79.3	80.2	81.1	82.0	82.8	83.7	84.6	85.6
120..............	77.2	78.1	79.0	79.9	80.8	81.7	82.5	83.4	84.3	85.2

TEMPERATURE—VOLUME TABLE

Showing Change in Volume for One Degree (Fahrenheit) Change in Temperature for 14° Be. Oil

Temp. Deg. F.	Correction to be Added	Temp. Deg. F.	Correction Subtract	Temp. Deg. F.	Correction Subtract	Temp. Deg. F.	Correction Subtract
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.021900
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.022265
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.022630
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.022995
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.023360
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.023725
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.024090
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.024455
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.024820
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.025185
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.025550
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	131	.025915
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	132	.026280
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	133	.026645
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	134	.027010
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	135	.027375
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	136	.027740
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	137	.028105
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	138	.028470
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	139	.028835
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.029200
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	141	.029565
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	142	.029930
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	143	.030295
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	144	.030660
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	145	.031025
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	146	.031390
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	147	.031755
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	148	.032120
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	149	.032485

To get proper correction multiply gross barrels by the number opposite the temperature. When the temperature is above [illegible]° F. the correction is subtracted from the gross barrels. When the temperature is below [illegible]° F. the correction is added. This table is based on [illegible] change in volume for one degree Fahrenheit change in temperature, [illegible] 14° Be. gravity. For oils of [illegible] coefficient of expansion per degree Fahrenheit:

[illegible]

HEAT UNITS PER BARREL

The commercial unit—Weight per barrel of different fuel oils according to the Baume scale with the respective heating values per barrel calculated from the formula of Sherman & Kropff, i. e., B. T. U's per pound of oil. equals 18650 added to 40 times the difference between the degree Baume and 10:

$$B. T. U. = 18650 \text{ plus } 40 \times (\text{Baume}—10.)$$

TEMPERATURE DEDUCTION TABLE

Temperatures in degrees Fahrenheit. Deduction in degrees Baume

Temperature	Addition	Temperature	Deduction	Temperature	Deduction	Temperature	Deduction	Temperature	Deduction	Temperature	Deduction
35	1.25	61	.05	89	1.45	117	2.85	145	4.25	173	5.65
36	1.20	62	.10	90	1.50	118	2.90	146	4.30	174	5.70
37	1.15	63	.15	91	1.55	119	2.95	147	4.35	175	5.75
38	1.10	64	.20	92	1.60	120	3.00	148	4.40	176	5.80
39	1.05	65	.25	93	1.65	121	3.05	149	4.45	177	5.85
40	1.00	66	.30	94	1.70	122	3.10	150	4.50	178	5.90
41	.95	67	.35	95	1.75	123	3.15	151	4.55	179	5.95
42	.90	68	.40	96	1.80	124	3.20	152	4.60	180	6.00
43	.85	69	.45	97	1.85	125	3.25	153	4.65	181	6.05
44	.80	70	.50	98	1.90	126	3.30	154	4.70	182	6.10
45	.75	71	.55	99	1.95	127	3.35	155	4.75	183	6.15
46	.70	72	.60	100	2.00	128	3.40	156	4.80	184	6.20
47	.65	73	.65	101	2.05	129	3.45	157	4.85	185	6.25
48	.60	74	.70	102	2.10	130	3.50	158	4.90	186	6.30
49	.55	75	.75	103	2.15	131	3.55	159	4.95	187	6.35
50	.50	76	.80	104	2.20	132	3.60	160	5.00	188	6.40
51	.45	77	.85	105	2.25	133	3.65	161	5.05	189	6.45
52	.40	78	.90	106	2.30	134	3.70	162	5.10	190	6.50
53	.35	79	.95	107	2.35	135	3.75	163	5.15	191	6.55
54	.30	80	1.00	108	2.40	136	3.80	164	5.20	192	6.60
55	.25	81	1.05	109	2.45	137	3.85	165	5.25	193	6.65
56	.20	82	1.10	110	2.50	138	3.90	166	5.30	194	6.70
57	.15	83	1.15	111	2.55	139	3.95	167	5.35	195	6.75
58	.10	84	1.20	112	2.60	140	4.00	168	5.40	196	6.80
59	.05	85	1.25	113	2.65	141	4.05	169	5.45	197	6.85
60	.00	86	1.30	114	2.70	142	4.10	170	5.50	198	6.90
		87	1.35	115	2.75	143	4.15	171	5.55	199	6.95
		88	1.40	116	2.80	144	4.20	172	5.60	200	7.00

To make gravity corrections for temperature. Take temperature and gravity readings from the Hydrometer at the same time and make deductions for temperature as per above table.

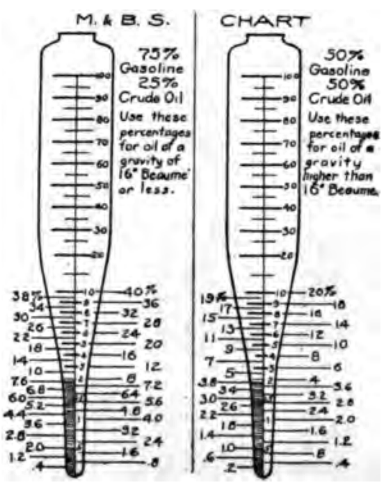
For example, if it is found that the gravity according to your Hydrometer is 19.8 and the temperature according to the Hydrometer is 106 degrees Fahrenheit you would deduct 2.3 degrees from 19.8 degrees which, would give a corrected gravity of 17.5 degrees Baume.

CAUTION.—Never insert Hydrometer in oil hotter than the highest temperature indicated on your Hydrometer thermometer. Always test oil first with Station Thermometer and if necessary allow oil to cool before inserting Hydrometer.

DIRECTIONS FOR TESTING OIL FOR IMPURITIES

In making 75% cut proceed as follows: Pour 75 C. C. of gasoline into the graduated tube. Then pour in 25 C. C. of crude oil, filling the tube to the 100 C. C. mark. Shake the tube thoroughly for about 5 minutes, place in rack, and allow to settle.

If it is found that the cut line is at the graduation marked 2 on the tube, to obtain correct cut multiply by 4 which would give 8% M. and B. S.



In making 50% cut fill the tube half full of gasoline, that is, to the 50 C. C. mark. Then pour in crude oil filling the tube to the 100 C. C. mark.

Proceed as in making 75% cut with the exception that the observed location of the cut line must be multiplied by 2 to give correct M. and B. S.

Baume	Lbs. per bbl.	B. T. U's per bbl.	B. T. U's per bbl. 35 Baume Oil	Difference in favor of heavy oil: No. of B. T. U's Per bbl.	Difference in favor of heavy oil: Per Ct.
10	349	6,525,635	5,842,338	683,297	11.69
11	347	6,494,027	5,842,338	651,689	11.15
12	344	6,461,288	5,842,338	618,950	10.60
13	342	6,431,352	5,842,338	589,014	10.08
14	340	6,398,666	5,842,338	556,328	9.53
15	338	6,371,677	5,842,338	529,339	9.06
16	335	6,340,239	5,842,338	497,901	8.53
17	333	6,311,829	5,842,338	469,491	8.03
18	331	6,282,294	5,842,338	439,956	7.53
19	328	6,253,199	5,842,338	410,961	7.03
20	326	6,225,540	5,842,338	383,202	6.55
21	324	6,198,523	5,842,338	356,185	6.09
22	322	6,169,807	5,842,338	327,469	5.60
23	320	6,143,985	5,842,338	301,647	5.16
24	318	6,117,464	5,842,338	275,126	4.71
25	316	6,090,892	5,842,338	248,554	4.25
26	314	6,064,197	5,842,338	221,859	3.79
27	312	6,038,112	5,842,338	195,774	3.35
28	310	6,013,610	5,842,338	171,272	2.93
29	308	5,986,820	5,842,338	144,482	2.47
30	306	5,963,370	5,842,338	121,042	2.07
31	304	5,938,018	5,842,338	95,680	1.63
32	302	5,914,074	5,842,338	71,736	1.22
33	301	5,890,765	5,842,338	48,427	.82
34	299	5,866,527	5,842,338	24,189	.41
35	297	5,842,338	5,842,338		

Standard Size and Weights—Wrought Iron and Steel Pipe and Casing As Used In Gulf Coast Country

Size, ins.	List Price Per ft.	Diameter, ins. External	Diameter, ins. Internal	Thickness	Nominal O. D. of Coupling	Nominal Length of Coupling	Weight Per Foot: Plain Ends	Weight Per Foot: Threads and Couplings	Threads per Inch
⅛	$ .06	.405	.269	.068	18/32	⅞	.244	.246	27
¼	.06½	.540	.364	.088	23/32	15/16	.424	.426	18
⅜	.06½	.675	.493	.091	63/64	1-⅛	.567	.571	18
½	.09	.840	.622	.109	1-¼	1-25/32	.850	.856	14
¾	.12	1.050	.824	.113	1- 7/16	2- 7/32	1.130	1.138	14
1	.17½	1.315	1.049	.133	1-21/32	2- 7/32	1.678	1.688	11½
1¼	.23½	1.660	1.380	.140	2-⅛	2-⅞	2.272	2.300	11½
1½	.28	1.900	1.610	.145	2-⅜	3-¼	2.717	2.748	11½
2	.37½	2.375	2.067	.154	2-29/32	3-11/16	3.652	3.716	11½
2½	.59	2.875	2.469	.203	3-17/32	4- 3/16	5.793	5.881	8
3	.77	3.500	3.068	.216	4- 5/32	4- 3/16	7.575	7.675	8
3½	.93	4.000	3.548	.226	4-25/32	4- 3/16	9.109	9.261	8
4	1.10	4.500	4.026	.237	5- 7/32	4-¼	10.790	10.980	8
4½	1.28	5.000	4.506	.247	5-11/16	4- 3/16	12.538	12.742	8
5	1.50	5.563	5.047	.258	6-17/32	5-¼	14.617	14.966	8
6	1.94	6.625	6.065	.280	7-19/32	5-½	18.974	19.367	8
7	2.40	7.625	7.023	.301	8-⅝	6-⅜	23.544	23.975	8
8	2.54	8.625	8.071	.277	9-½	6-⅜	24.696	25.414	8
8	2.92	8.625	7.981	.322	9-½	6-⅜	28.554	29.213	8
9	3.47	9.625	8.941	.342	10-19/32	6-⅜	33.907	34.612	8
10	3.25	10.750	10.192	.279	11-⅞	6-½	31.201	32.515	8
10	3.55	10.750	10.136	.307	11-⅞	6-½	34.240	35.504	8
10	4.17	10.750	10.020	.365	11-⅞	6-½	40.483	41.644	8
11	4.68	11.750	11.000	.375	12-31/32	6-⅝	45.557	46.805	8
12	4.55	12.750	12.090	.330	13-15/16	6-½	43.773	45.217	8
12	5.12	12.750	12.000	.375	13-15/16	6-½	49.562	50.916	8
13	5.68	14.000	13.250	.375	15-13/32	7- 1/16	54.568	56.649	8
14	6.18	15.000	14.250	.375	16-11/32	7-¼	58.573	60.802	8
15	6.60	16.000	15.250	.375	17-⅜	7-¼	62.579	64.955	8

Rotary Pipe or Drill Stem—Iron and Steel: All Weights and Dimensions are Nominal

Size	Diameters External	Diameters Internal	Thickness	Nominal O. D. of Coupling	Nominal Length of Coupling	Weight Per Foot Plain Ends	Weight Per Foot Threads and Couplings	Threads Per Inch
4	4.500	4.026	.237	5– 9/16	6–⅝	10.790	11.055	8
4	4.500	3.900	.255	5– 9/16	6–⅝	11.561	11.815	8
4½	5.000	4.506	.247	5–15/16	7–⅛	12.538	12.744	8
5	5.563	5.047	.258	6– 7/16	7–¼	14.617	15.055	8
6	6.625	6.065	.280	7–17/32	7–¼	18.974	19.463	8

Special Rotary Pipe—Iron and Steel: All Weights and Dimensions are Nominal

Size	Diameters External	Diameters Internal	Thickness	Nominal O. D. of Coupling	Nominal Length of Coupling	Weight Per Foot Plain Ends	Weight Per Foot Threads and Couplings	Threads Per Inch
2½	2.875	2.323	.276	3–11/16	5–⅛	7.661	7.830	8
2½	2.875	2.143	.366	3–11/16	5–⅛	9.807	10.000	8
4	4.500	3.958	.271	5– 9/16	6–⅝	12.240	12.000	8
4	4.500	3.826	.337	5– 9/16	6–⅝	14.983	15.000	8
4½	5.000	4.388	.306	5–15/16	7–⅛	15.340	15.500	8
4½	5.000	4.290	.355	5–15/16	7–⅛	17.611	18.000	8
5	5.563	4.955	.304	6– 7/16	7–¼	17.074	17.500	8
5	5.563	4.813	.375	6– 7/16	7–¼	20.778	21.000	8
6	6.625	5.937	.344	7–17/32	7–¼	23.076	23.500	8
6	6.625	5.761	.432	7–17/32	7–¼	28.573	29.000	8

California Special Casing—Iron and Steel: All Weights and Dimensions are Nominal

Size	Diameters External	Diameters Internal	Thickness	Nominal O. D. of Coupling	Nominal Length of Coupling	Weight Per Foot Plain Ends	Weight Per Foot Threads and Couplings	Threads Per Inch
4½	4.750	4.082	.334	5–15/32	6– 7/16	15.752	16.000	10
4¾	5.000	4.506	.247	5–17/32	8–⅛	12.538	12.850	10
4¾	5.000	4.424	.288	5–17/32	8–⅛	14.493	15.000	10
5⅝	6.000	5.352	.324	6–25/32	6–¼	19.641	20.000	10
6¼	6.625	6.049	.288	7– 7/16	10–¼	19.491	20.000	10
6¼	6.625	5.921	.352	7– 7/16	10–¼	23.582	24.000	10
6¼	6.625	5.855	.385	7– 7/16	10–¼	25.658	26.000	10
6¼	6.625	5.791	.417	7– 7/16	10–¼	27.648	28.000	10
6⅝	7.000	6.456	.272	7–23/32	10–¼	19.544	20.000	10
6⅝	7.000	6.276	.362	7–23/32	10–¼	25.663	26.000	10
6⅝	7.000	6.214	.393	7–23/32	10–¼	27.731	28.000	10
6⅝	7.000	6.154	.423	7–23/32	10–¼	29.712	30.000	10
7⅝	8.000	7.386	.307	8–31/32	7–¼	25.223	26.000	10
8¼	8.625	8.017	.304	9–19/32	10–¼	27.016	28.000	10
8¼	8.625	7.921	.352	9–19/32	10–¼	31.101	32.000	10
8¼	8.625	7.825	.400	9–19/32	10–¼	35.137	36.000	10
8¼	8.625	7.775	.425	9–19/32	10–¼	37.220	38.000	10
8¼	8.625	7.651	.487	9–19/32	10–¼	42.327	43.000	10
9⅝	10.000	9.384	.308	10–29/32	7– 3/16	31.881	33.000	10
10	10.750	10.054	.348	11–29/32	10–¼	38.661	40.000	10
10	10.750	9.960	.395	11–29/32	10–¼	43.684	45.000	10
10	10.750	9.902	.424	11–29/32	10–¼	46.760	48.000	10
10	10.750	9.784	.483	11–29/32	10–¼	52.962	54.000	10
11⅝	12.000	11.384	.308	13– 5/32	7– 3/16	38.460	40.000	10
12½	13.000	12.438	.281	14– 7/32	12–¼	38.171	40.000	10
12½	13.000	12.360	.320	14– 7/32	12–¼	43.335	45.000	10
12½	13.000	12.282	.359	14– 7/32	12–¼	48.467	50.000	10
12½	13.000	12.220	.390	14– 7/32	12–¼	52.523	54.000	10
13½	14.000	13.344	.328	15–15/32	8–⅛	47.894	50.000	10
15½	16.000	15.198	.401	17–15/32	8	66.806	70.000	10

Oil Well Tubing—Iron and Steel: All Weights and Dimensions are Nominal

Size	Diameters External	Diameters Internal	Thickness	Nominal O. D. of Coupling	Nominal Length of Coupling	Weight Per Foot Plain Ends	Weight Per Foot Threads and Couplings	Threads Per Inch
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2.300	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2.748	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4.000	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4.433	4.500	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	8.388	[illegible]	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11½
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11.561	[illegible]	8

The permissible variation in weight is 5 per cent above and 5 per cent below. Furnished with threads and couplings and in random lengths, unless otherwise ordered. All weights are given in pounds. All dimensions given in inches. Steel always unless specified differently.

Drive Pipe—Iron and Steel

Size	Diameters External	Diameters Internal	Thickness	Nominal O. D. of Coupling	Nominal Length of Coupling	Weight Per Foot Plain Ends	Weight Per Foot Threads and Couplings	Threads Per Inch
2	2.375	[illegible]	.154	[illegible]	3-11/16	3.652	3.730	11½
2½	2.875	[illegible]	.203	[illegible]	4-3/16	5.793	5.906	8
3	3.500	[illegible]	[illegible]	[illegible]	[illegible]	7.575	7.705	8
3½	4.000	3.548	[illegible]	[illegible]	[illegible]	9.109	9.294	8
4	4.500	4.026	[illegible]	[illegible]	[illegible]	10.790	10.995	8
4½	5.000	4.506	[illegible]	[illegible]	4-3/16	12.538	12.758	8
5	5.563	[illegible]	.258	[illegible]	[illegible]	14.617	14.989	8
6	6.625	[illegible]	.280	[illegible]	[illegible]	18.974	19.408	8
7	7.625	[illegible]	.301	[illegible]	6-5/16	23.544	24.021	8
8	8.625	[illegible]	[illegible]	[illegible]	[illegible]	24.696	25.495	8
8	8.625	[illegible]	.322	[illegible]	[illegible]	28.554	29.303	8
8	[illegible]	[illegible]	.354	[illegible]	[illegible]	31.270	32.334	8
[illegible]	[illegible]	[illegible]	.342	[illegible]	[illegible]	33.907	34.711	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	31.201	32.631	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	34.240	35.628	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	40.483	41.785	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	45.557	46.953	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	43.773	45.358	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	49.562	51.067	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	54.568	56.849	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	58.573	61.005	8
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	62.579	65.161	8
[illegible] OD	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	69.704	73.000	8
[illegible] OD	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	76.840	81.000	8
[illegible] OD	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	85.577	90.000	8

External Upset Tubing

Size	Diameters External	Diameters Internal	Thickness	Weight Per Foot Plain Ends	Weight Per Foot Threads and Couplings	Test Pressure in Pounds	Threads Per Inch	Couplings Diameter	Couplings Length	Couplings Weight
1¼	1.660	[illegible]	[illegible]	[illegible]	[illegible]	1800	11½	2.200	2⅞	1.049
1½	1.900	[illegible]	[illegible]	2.717	[illegible]	1800	11½	2.481	2⅞	1.049
2	2.375	[illegible]	[illegible]	[illegible]	[illegible]	2200	11½	3.060	3⅝	2.329
2	2.375	1.995	[illegible]	4.433	4.500	2500	11½	3.060	3⅝	2.329
2½	2.875	2.441	.217	[illegible]	6.250	2200	11½	3.668	4⅛	3.891
3	3.500	3.018	.241	8.388	8.627	2000	10	4.504	5⅛	7.627
4	4.500	3.958	.271	12.240	12.500	1800	10	5.349	6⅛	9.511

"Shelby" Seamless Interior Upset Drill Pipe

Size	Diameters External	Diameters Internal	Thickness	Weight Per Foot Plain Ends	Weight Per Foot Threads and Couplings	Test Pressure in Pounds	Threads Per Inch	Couplings Diameter	Couplings Length	Couplings Weight
2	2.375	2.000	.1875	4.380	4.477	2500	10	2.892	5⅛	3.503
2½	2.875	2.469	.203	5.793	6.002	2200	8	3.564	6⅛	6.743
2½	2.875	2.323	.276	7.661	7.841	2500	8	3.564	6⅛	6.743
3	3.500	3.063	.2187	7.665	7.939	1800	8	4.248	6⅛	8.777
3½	4.000	3.500	.250	10.012	10.366	2000	8	4.771	7⅛	12.060
4	4.500	4.000	.250	11.347	11.756	1800	8	5.256	7⅝	14.296
4	4.500	3.958	.271	12.240	12.632	1900	8	5.256	7⅝	14.296
4	4.500	3.826	.337	14.983	15.323	2200	8	5.256	7⅝	14.296
4½	5.000	4.500	.250	12.682	13.130	1700	8	5.756	7⅝	15.787
5	5.563	4.975	.294	16.544	17.000	1700	8	6.303	8⅛	18.472
5	5.563	4.859	.352	19.590	20.000	2000	8	6.303	8⅛	18.472
6	6.625	6.065	.280	18.974	19.551	1600	8	7.350	8⅝	22.994
6	6.625	5.761	.432	28.573	28.948	2000	8	7.350	8⅝	22.994

Table Showing Collapsing Pressure of Lap-Welded Steel Casing

Size, Inches	Weight Per Foot, Pounds	Inside Diameter, Inches	Outside Diameter	Thickness, Inches	Collapsing Pressure Pounds, Square Inch	Equivalent Water Column Feet	Using Safety Fac. of 2
4	15.0	3.826	4.500	0.337	5105	11760	5880
4-½	15.0	4.500	5.000	0.250	2944	6790	3395
5-3/16	17.0	4.892	5.500	0.304	3404	7840	3920
5-3/16	20.0	4.780	5.500	0.360	4285	9870	4935
5-⅝	20.0	5.370	6.000	0.315	3160	7280	3640
6	17.0	4.982	5.500	0.304	3404	7840	3920
6	19.46	6.065	6.625	0.280	2277	5246	2623
6	23.5	5.937	6.625	0.344	3114	7170	3585
6-¼	20.0	6.000	6.625	0.312	2704	6230	3115
	26.0	5.845	6.625	0.390	3717	8560	4280
	28.0	5.775	6.625	0.425	4167	9600	4800
6-⅝	20.0	6.437	7.000	0.281	2096	4830	2415
6-⅝	24.0	6.334	7.000	0.333	2741	6320	3160
	26.0	6.312	7.000	0.344	2867	6600	3300
	28.0	6.220	7.000	0.390	3440	7930	3965
7-⅝	26.0	7.390	8.000	0.305	1914	4410	2205
8	29.213	7.981	8.625	0.322	1849	4260	2130
8-¼	28.0	8.015	8.625	0.305	1980	3870	1935
	32.0	7.935	8.625	0.345	2080	4790	2395
	36.0	7.875	8.625	0.375	2383	5490	2745
	38.0	7.765	8.625	0.430	2928	6750	3375
	43.0	7.625	8.625	0.500	3638	8380	4190
9-⅝	33.0	9.500	10.000	0.250	780	1800	900
10	40.0	10.000	10.750	0.375	1638	3770	1885
	48.0	9.850	10.750	0.450	2234	5150	2575
	54.0	9.750	10.750	0.500	2643	6090	3045
11-⅝	40.0	11.437	12.000	0.281	641	1475	737
12-½	40.0	12.500	13.000	0.250	402	927	463
	45.0	12.360	13.000	0.320	745	1717	858
	50.0	12.250	13.000	0.375	1109	2560	1280
13-½	50.0	13.250	14.000	0.375	936	2160	1080
15-½	51.3	15.416	16.000	0.292	314	724	362

WROUGHT STEEL PIPE
BURSTING AND WORKING PRESSURES*

Size	Standard		Extra Strong		Double Extra Strong		Large O. D.			
Inches	Bursting Pressure Barlow's Formula	Working Pressure Factor 8	Bursting Pressure Barlow's Formula	Working Pressure Factor 8	Bursting Pressure Barlow's Formula	Working Pressure Factor 8	[illegible] inch Thick Bursting Pressure Barlow's Formula	Working Pressure Factor 8	[illegible] inch Thick Bursting Pressure Barlow's Formula	Working Pressure Factor 8
1/8	13,432	1679	18,760	3065						
1/4	13,032	1629	17,624	2953						
3/8	10,784	1348	14,928	1866						
1/2	10,384	1298	14,000	1750	28,000	3500				
3/4	8,608	1076	11,728	1716	23,464	2933				
1	8,088	1011	10,888	1611	21,776	2722				
1 1/4	6,744	843	9,200	1150	18,408	2301				
1 1/2	6,104	763	8,416	1052	16,840	2105				
2	5,184	648	7,336	917	14,680	1835				
2 1/2	5,648	706	7,680	960	15,360	1920				
3	4,936	617	6,856	857	13,714	1714				
3 1/2	5,610	701	7,950	994	15,900	1987				
4	5,266	658	7,480	935	14,970	1871				
4 1/2	4,940	618	7,100	887	14,200	1775				
5	4,630	579	6,740	842	13,480	1685				
6	4,220	528	6,520	815	13,040	1630				
7	3,940	493	6,550	819	11,470	1434				
8	3,730	466	5,780	722	10,140	1267				
9	3,550	444	5,190	649						
10	3,390	424	4,650	581						
12	2,940	368	3,920	490						
14							2,680	335	3,570	446
15							2,500	313	3,333	417
16							2,340	293	3,120	390
18							2,080	260	2,770	346
20							1,870	234	2,500	313
22							1,700	213	2,270	284
24							1,560	195	2,080	260

In the above table, butt welded pipe was figured on sizes 3 inch and smaller and lap welded pipe sizes 3 1/2 inch and larger.

Table Showing Capacity of Tubing and Casing Per Lineal Foot In Gallons and Cubic Feet

Nominal Inside Diameter	Weight, Per Foot Pounds	Actual Outside Diameter, Inches	Actual Inside Diameter Inches	Capacity Per Foot Gallons	Capacity Per Foot Cubic Feet
1¼	2.24	1.660	1.390	0.079	0.0105
1½	2.68	1.900	1.622	0.1078	0.0144
2	4.00	2.375	2.021	0.1661	0.0222
2	4.50	2.375	1.971	0.1582	0.0212
2½	5.74	2.875	2.461	0.2470	0.0330
2½	6.25	2.875	2.433	0.2420	0.0323
3	7.54	3.500	3.080	0.3870	0.0158
3	8.50	3.500	3.018	0.3720	0.0497
3	10.00	3.500	2.914	0.3460	0.0463
3½	9.00	4.000	3.558	0.5160	0.0689
4	10.66	4.500	4.022	0.6600	0.0882
4	11.75	4.500	3.980	0.6510	0.0870
4½	16.00	4.750	4.082	0.680	0.091
4½	12.85	5.000	4.506	0.830	0.116
4½	15.00	5.000	4.424	0.799	0.107
5⅝	20.00	6.000	5.352	1.170	0.156
6¼	20.00	6.625	6.049	1.490	0.199
6¼	24.00	6.625	5.921	1.430	0.191
6¼	26.00	6.625	5.855	1.400	0.187
6¼	28.00	6.625	5.791	1.365	0.182
6⅝	20.00	7.000	6.456	1.700	0.227
6⅝	26.00	7.000	6.276	1.610	0.215
6⅝	28.00	7.000	6.214	1.580	0.211
6⅝	30.00	7.000	6.154	1.546	0.206
7⅝	26.00	8.000	7.386	2.224	0.296
8¼	28.00	8.625	8.017	2.625	0.350
8¼	32.00	8.625	7.921	2.560	0.343
8¼	36.00	8.625	7.825	2.500	0.334
8¼	38.00	8.625	7.775	2.470	0.330
8¼	43.00	8.625	7.651	2.390	0.320
9⅝	33.00	10.000	9.384	3.600	0.480
10	40.00	10.750	10.054	4.130	0.552
10	45.00	10.750	9.960	4.060	0.543
10	48.00	10.750	9.902	4.020	0.537
10	54.00	10.750	9.784	3.900	0.522
11⅝	40.00	12.000	11.384	5.290	0.706
12½	40.00	13.000	12.438	6.300	0.843
12½	45.00	13.000	12.360	6.230	0.834
12½	50.00	13.000	12.282	6.140	0.821
12½	54.00	13.000	12.220	6.090	0.814
13½	50.00	14.000	13.344	7.280	0.973
15½	70.00	16.000	15.198	9.420	1.260

Contents of Cylinders in Cubic Feet and in U. S. Gallons Per One Foot in Length

[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]

Diameter in inches	Diameter in Decimals of a foot	For one foot in length Cubic Feet, also area in sq. ft.	Gallons of 231 cubic inches
8¼	.6875	.3713	2.777
½	.7083	.3940	2.948
¾	.7292	.4175	3.125
9	.750	.4418	3.305
¼	.7708	.4668	3.492
½	.7917	.4923	3.682
¾	.8125	.5185	3.879
10	.8333	.5455	4.081
¼	.8542	.5730	4.286
½	.8750	.6013	4.498
¾	.8958	.6303	4 714
11	.9167	.660	4.937
¼	.9375	.6903	5.163
½	.9583	.7213	5.395
¾	.9792	.7530	5.633
12	1.0	.7854	5.876
½	1.042	.8523	6.375
13	1.083	.9218	6.895
½	1.125	.9940	7.435
14	1.167	1.069	7.997
½	1.208	1.147	8.578
15	1.250	1.227	9.180
½	1.292	1.310	9.801
16	1.333	1.396	10.44
½	1.375	1.485	11.11
17	1.417	1.576	11.79
½	1.458	1.670	12.50
18	1.50	1.767	13.22
½	1.542	1.867	13.97
19	1.583	1.969	14.73
½	1.625	2.074	15.52
20	1.666	2.182	16.32
½	1.708	2.292	17.15
21	1.750	2.405	17.99
½	1.792	2.521	18.86
22	1.833	2.640	19.75

231 cubic inches equals one gallon, and 7.4805 gallons equals one cubic foot.
For the contents of a greater diameter than any in the table, take the quantity opposite one-half said diameter, and multiply it by four.

AUXILIARY APPARATUS AS AN AID TO FUEL SAVING[1]

Feed water softeners and treaters.—All natural water, except rain water, contains chemicals in solution or suspension which may appear as solids under boiler conditions. When by analysis such solid-forming compounds are determined in water they may be removed or rendered harmless by some method of treatment.

Against the cost of this treatment is balanced the decreased capacity and efficiency of the boiler when fired through scaly tubes, the depreciation of the tubes, and also the frequency of cleaning and repairs with the necessary shutdowns.

Scale is formed by the deposit of these compounds on the heat-

[1] U. S. Bureau of Mines handbook, "Efficiency in the use of oil fuel."

ing surface, through their concentration in the process of evaporation, the lower power of the water to hold them in solution at high temperatures, and the chemical reactions produced by concentration and temperature. It may also be formed by mud and sediment being cemented with other impurities of the surface.

Approximate Classification of Impurities Found in Feed Waters, Their Effect, and Ordinary Methods of Relief

Impurity	Nature of Difficulty	Ordinary Method of Overcoming or Relieving
Sediment, mud, etc	Incrustation	Settling tanks, filtration. Blowing down.
Readily soluble salts	do	Blowing down.
Bicarbonate of lime, magnesia, etc.	do	Heating feed. Treatment by addition of lime, or lime and soda, Barium carbonate.
Sulphate of lime	do	Treatment by addition of barium carbonate.
Chloride and sulphate of magnesia	Corrosion	Treatment by addition of carbonate of soda.
Acid	do	Alkali.
Dissolved carbonic acid and oxygen	do	Heating feed. Keeping air from feed. Addition of caustic soda or slacked lime.
Grease	do	Filter. Iron alum as coagulant.
Organic matter	do	Neutralization by carbonate of soda. Use of best hydro-carbon oils.
Organic matter (sewage)	Priming	Filter. Use of coagulant. Settling tanks. Filter in connection with coagulant.
Carbonate of soda in large quantities	do	Barium carbonate new feed supply if from treatment, change.

In general one can say that it always pays to treat a poor feed water and, further, the treatment should be outside the boiler. Boiler compounds should be used only when treatment plants are not feasible. Treatment plants use different chemical reagents for precipitating the scale-forming substance in water-soda and lime being the most common. Tannins or other chemicals forming colloidal solutions are sometimes used.

The losses from firing through scale, and from foaming priming caused by impurities, although difficult to express in precise terms, are nevertheless actual and quite evident upon careful observation.

Feed water heaters.—The fuel saving possible from heating feed water may be computed from the formula:

$$\text{Percentage of fuel saving} = \frac{100\ (t - t^1)}{H \times 32 - t^1}$$

where t equals the feed water temperature after heating, t^1 the temperature of feed water before heating, and H is the heat content above 32 degrees Fahrenheit per pound of steam at boiler pressure.

An approximate rule for the conditions of ordinary practice is that a saving of 1 per cent is made by each increase of 11 degrees Fahrenheit in the temperature of the feed-water. This corresponds to 0.0909 per cent per degree of temperature rise.

The calculation of saving is made as follows: Boiler-pressure 100 pounds gauge; total heat in steam above 32 degrees equals 1,185 b. t. u. Feed-water original temperature, 60 degrees; final temperature, 209 degrees Fahrenheit. Increase in heat units, 150. Heat-units above 32 degrees in feed-water of original temperature equals 28. Heating units in steam above that in cold feed-water, 1,185 less 28 equals 1,157. Saving by the feed-water heater equals 150/1,157 equals 12.96 per cent. Increase in temperature 150 degrees times tabular figure 0.0864 equals 12.96 per cent.

Exhaust steam from the main auxiliary machinery is usually used in both the open and closed types of heater for heating the feed water. Economizers are sometimes used in the flue passages from a boiler for preheating the feed water, and are generally constructed as a continuous coil or are improvised from a discarded tubular boiler. Where a boiler is not abstracting the proper proportion of heat from the combustion gases an economizer has a proper field. Otherwise, with the good efficiencies of 75 to 80 per cent possible with oil fuel, there is small opportunity for much gain from installing economizers. The selection of a feed-water heater should be intrusted to an engineer who has made a study of the conditions at the particular plant.

Superheaters

In the transportation of saturated steam to the main engines all radiation of heat from the piping has its equivalent in condensation within the line, whereas with superheat the radiation simply causes a loss of superheat but no condensation. In addition the conductibility of superheated steam is less than that of saturated and the radiation losses are lower.

Within the engine cylinder, entering steam is required im-

mediately to supply heat to the relatively cool cylinder walls. The result with saturated steam is a condensation loss of 20 to 30 per cent. Assume that a certain cylinder requires 1 pound of steam at a pressure of 150 pounds to fill it to the point of cut-off. As the volume of 1 pound of steam at that pressure is about 170 times as great as the volume of 1 pound of water, the space occupied by the condensed water is slight as compared with that of the steam, and an additional volume of steam practically equal to that condensed will have to be supplied, or practically 1.25 pounds of steam will be required.

On the contrary, if the degree of superheat is sufficient, superheated steam gives no condensation in the cylinder and every pound of steam from the boiler does useful work in the cylinder. It is the practice to govern the amount of superheat so as to obviate most of the condensation and at the same time to avoid the difficulty of lubrication and the new or special engine valves, steam lines, and fittings made necessary by excessively high temperatures. In general the fuel saving from a superheater placed properly will practically equal the percentage of steam saved.

Boiler Horse Power[1]

The accepted rule for figuring boiler horse power is as follows:

One Horse Power equals the evaporation of 30 pounds of water per hour from an initial temperature of 100 degrees Fahrenheit into steam at 70 pounds gauge pressure, or its equivalent; 34½ pounds of water evaporated per hour from a temperature of 212 degrees Fahrenheit into steam at 212 degrees.

Horse Power of an Engine[1]

P = mean effective pressure per square inch of the steam on the piston.
L = length of stroke in feet.
A = area of piston in square inches.
N = number of strokes per minute.

Then Horse Power equals $\frac{PLAN}{33000}$

The approximate mean effective pressure in the cylinder when valve cuts off at:

[1]By Permission of Crane Company.

¼ stroke equals steam pressure × .597
⅓ stroke equals steam pressure × .670
⅜ stroke equals steam pressure × .743
½ stroke equals steam pressure × .847
⅝ stroke equals steam pressure × .919
⅔ stroke equals steam pressure × .937
¾ stroke equals steam pressure × .966
⅞ stroke equals steam pressure × .922

Ranges In Steam Consumption By Prime Movers[1]

(For Estimating Purposes)

Simple Non-Condensing Automatic Engines..	29-45 pounds per hour.
Simple Non-Condensing Engines............	26-40 pounds per hour.
Simple Non-Condensing Corliss Engines.....	26-35 pounds per hour.
Compound Non-Condensing Engines........	19-28 pounds per hour.
Compound Condensing Engines.............	12-22 pounds per hour.
Simple Duplex Steam Pumps................	120-200 pounds per hour.
Turbines, Non-Condensing..................	28-60 pounds per K.W. hr.
Turbines, Condensing	12-42 pounds per K.W. hr.

Flow of Steam In Pipes[1]

To determine the velocity of steam in feet per minute through a pipe, the quantity, pressure and area being known.

V = velocity in feet per minute.
A = pounds of steam per hour.
B = volume in cubic feet of 1 pound at given pressure.
C = area of pipe in square inches.
1728 = cubic inches in a cubic foot.
60 = minutes in an hour.
12 = inches in a foot.

$$\text{Then } V = \frac{A \times B \times 1728}{60 \times C \times 12} = \frac{A \times B \times 2.4}{C}$$

$$\text{Or } A = \frac{C \times V}{B \times 2.4}$$

$$\text{Or } B = \frac{C \times V}{A \times 2.4}$$

$$\text{Or } C = \frac{A \times B \times 2.4}{V}$$

[1]By Permission of Crane Company.

Loss of Pressure[1]

The above formula does not consider the probable drop, or loss of pressure which is dependent upon the velocity of flow, length of line, number of turns in fittings or valves, and the covering of the pipe. In every steam line there must be a difference in pressure between the inlet and outlet or there could be no flow, and this difference is increased by friction and radiation.

In power plant work a steam velocity of 4000 to 6000 feet per minute may be employed without excessive loss, in properly covered pipes 6 inches diameter or larger. For smaller pipe use a lower velocity.

DETAILS CONCERNED WITH THE MAKING OF PIPE CONNECTIONS

Making Tight Screwed Joints for Very High Pressures[1]

By R. T. CRANE

We are in doubt if the trade clearly understands the conditions that are necessary in order to make good screw joints with pipe and fittings, especially when they are intended to withstand very high pressure, and in any event we think it might be best to put this matter before you once more.

It has been our experience that the ordinary steamfitter, when called upon to put up piping that will be subjected to a pressure of 200 or 300 pounds of steam, feels that he is shouldering a very heavy responsibility; but should he be called upon to make joints that would have to bear 1000 pounds of air pressure he might not feel like assuming the responsibility at all; or, should he undertake the work, probably he would feel certain that it would be necessary to resort to extraordinary means to get the desired result. In all probability he would decide that with the ordinary material manufactured and supplied to the general market, such work under these conditions was impossible.

We have demonstrated beyond the possibility of a doubt, that tight joints for 1000 pounds air may be made with the ordinary line pipe, providing clean cut threads are made, and extraordinary care and intelligence are exercised in putting them together.

[1]By Permission Crane Co.

The secret of making a tight joint is to avoid or overcome the friction incident to screwing pipe and fittings together.

This friction is due to the large amount of bearing surface, especially when there is grit in the threads and the joints are coming up close to the bearing. Friction produces heat, and heat produces expansion, and as the pipe is lighter than the coupling or fitting, it expands more; then when both become cold the pipe contracts more than the coupling, thus causing a tendency to leak.

Some years ago we ran across an instance where a pipe line was being put together in the field by machinery. The machine would do the work quickly, and the workmen concluded that they had tight joints, when the joints became hot; but after the material was cold, and the heat of the friction was gone, the joints would not be tight. The fact of the matter was that the heat showed conclusively that the threads had not been properly cleaned, and instead of the heat being an evidence of a tight joint, it was evidence of a bad joint, and we have no doubt that there has been, and still is, an enormous amount of pipe line work being botched up in this way.

Some time ago we took occasion to make a test on this question on an eight-inch pipe line to withstand 1,000 pounds of air pressure; and this we did with the regular weight of line pipe and a coupling weighing about 24 pounds—the weight of a first-class line pipe coupling of this size. The result of the experiment on thirty-two joints was that on the first test all were tight excepting one, and when this joint was taken apart and again made up, it also proved tight.

These cases simply prove that it is a comparatively easy matter to make tight joints for 1,000 pounds air pressure, and with the ordinary pipe line material.

It must be evident to anyone who has given any thought whatever to this subject, that in order to make good joints, the iron must be brought together as solidly as possible.

To secure this result the first essential is that the threads should be absolutely clean; and the next is that the very best lubricant should be used in order to prevent friction, and they should not be screwed up fast enough to make any change in the temperature of the material.

It is necessary that the threads be cut clean, that is, that taps and dies be in perfect condition.

A taper thread is not absolutely necessary to the making of a tight joint. (In one experiment we made one joint with coupling which had no taper at all, and the others but very little.) Nor is a large amount of bearing necessary to make a tight joint—although for permanency and serviceability the standard length of threads and taper we consider necessary and correct.

We made one joint with a thread reduced to three-eights of an inch in length and it was tight at 1,500 pounds hydraulic pressure, thus proving that the length of thread is not essential to prevent the stripping of the thread, either from the pipe or from the coupling.

We are satisfied that especially long threads are a detriment to the making of a good joint; for it must stand to reason, that the longer the thread the more the tendency to friction, which prevents the iron from coming up close together, not to mention the natural irregularities in the threads acting in the same direction.

This will be better understood if we go to an extreme in the matter. For instance, should we undertake to make a joint on eight inch pipe, with a thread six inches long, the friction and irregularities would be so great that it would be practically impossible to get the requisite thread contact.

It should be understood that absence of heat in pipe or coupling does not mean absence of grit or gum in the threads. Dirty threads may be screwed up very slowly, and thus avoid the heating due to friction, and yet the joints be anything but tight.

Defects in Threads on Wrought Iron or Steel Pipe and Fittings[1]

It is surprising what erroneous ideas are held regarding the placing of too much importance on defects in threads of pipe and fittings, by those whose business it is to make joints with them.

In order to show how mistaken are these ideas, Crane Company, some time ago made the most searching and conclusive tests, giving abundant evidence that the many defects for which pipe and fittings often are rejected, are entirely unimportant and do not in the slightest, militate against the making of a thoroughly tight and serviceable joint.

[1]By R. T. Crane

-es assigned for the rejection of pipe and material -s are a trifle broken. Probably not so much as -e whole bearing of the thread is gone, or marred, -mfitters who will throw out such material.

-ny has shown conclusively, in the following prac-t is absurd to discard such material for ordinary -ds.

-ht-inch pipe was threaded for a distance of two and -s. This pipe was then put in a lathe and was muti-

-aded part three grooves were turned, each 3/16 of -and to the bottom of the thread. The top of the re-ds, with the exception of the one at the end of the -ned off, giving them a flat surface 1/32 of an inch

-hree places on the circumference of the tapered thread -e filed, one inch wide and two inches long, extending -the threaded part.

-ve grooves were then filed in the thread of the pipe -e number in the coupling, all parallel with the pipe and -f the depth of the thread.

-l this deliberate mutilating was finished, the threads -d thoroughly and coated with "Crane Cement." The -en screwed up so that the lengthwise grooves did not -ite one another.

-er ends of the pipe and coupling next were plugged and -nt was tested to 425 pounds of air pressure. The joint to be tight, and the same result followed a hydraulic -st of 1000 pounds.

-ount of defect in the thread of this joint was at least one -mes greater than that for which many regular steam-engineers reject material.

-tests show the amount of ignorance there has been in -ers all these years. Crane Company reasoned this subject -onfident the public held a wrong theory, caused this ex-o be made.

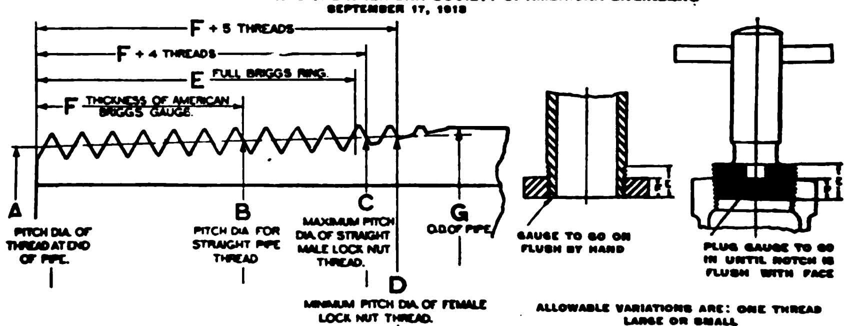
-tedly the amount of material rejected for minor and -mportant defects in the past, must have cost the trade -sands of dollars.

American Briggs Standard Gauge.—The threads in all our valves and fittings up to and including 12 inch, are tapped to American Briggs standard gauge, which has also been adopted as the universal standard by all the leading wrought pipe, valves and fittings manufacturers in the United States.

AMERICAN BRIGGS STANDARD FOR TAPER AND STRAIGHT PIPE THREADS AND LOCK-NUT THREADS

ADOPTED BY THE COMMITTEE OF MANUFACTURERS ON STANDARDIZATION OF FITTINGS AND VALVES AND THE AMERICAN SOCIETY OF AMERICAN ENGINEERS

SEPTEMBER 17, 1913



A equals $G-(0.05G+1.9)\times\frac{1}{N}+\frac{0.8}{N}$

B equals $A+(F\times.0625)$

C equals $B+\left(\frac{4}{N}\times.0625\right)$

D equals $B+\left(\frac{5}{N}\times.0625\right)$

E equals $(0.8G+4.8)\times\frac{1}{N}+\frac{2}{N}$

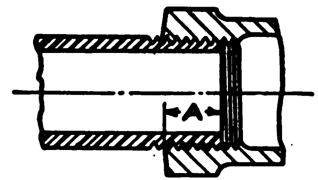
F equals American Briggs Standard.
N equals Number of threads per inch.
Total Taper ¾ inch per foot.

Depth of Thread $\frac{0.8}{N}$

Size	A	B	C	D	E	F	G	Depth of Thread	Threads per Inch
⅛	.36350	.37475	.38400	.38632	.2638	.180	.405	.02962	27
¼	.47739	.48989	.50378	.50725	.4018	.200	.540	.04444	18
⅜	.61201	.62701	.64090	.64437	.4078	.240	.675	.04444	18
½	.75843	.77843	.79628	.80075	.5337	.320	.840	.05714	14
¾	.96768	.98586	1.00671	1.01118	.5557	.339	1.050	.05714	14
1	1.21363	1.23863	1.26036	1.26580	.6828	.400	1.315	.06956	11½
1¼	1.55713	1.58338	1.60511	1.61055	.7068	.420	1.660	.06956	11½
1½	1.79609	1.82234	1.84407	1.84951	.7235	.420	1.900	.06956	11½
2	2.26902	2.29627	2.31801	2.32344	.7565	.436	2.375	.06956	11½
2½	2.71954	2.76216	2.79341	2.80122	1.1375	.682	2.875	.100	8
3	3.34063	3.38850	3.41975	3.42756	1.2000	.766	3.500	.100	8
3½	3.83750	3.88881	3.92006	3.92787	1.2500	.821	4.000	.100	8
4	4.33438	4.38713	4.41838	4.42619	1.3000	.844	4.500	.100	8
4½	4.83125	4.88593	4.91718	4.92499	1.3500	.875	5.000	.100	8
5	5.39074	5.44930	5.48055	5.48836	1.4063	.937	5.563	.100	8
6	6.44610	6.50597	6.53722	6.54503	1.5125	.958	6.625	.100	8
7	7.43985	7.50235	7.53360	7.54141	1.6125	1.000	7.625	.100	8
8	8.43360	8.50003	8.53128	8.53909	1.7125	1.063	8.625	.100	8
9	9.42735	9.49797	9.52922	9.53703	1.8125	1.130	9.625	.100	8
10	10.54532	10.62094	10.65219	10.66000	1.9250	1.21	10.750	.100	8
11	11.53907	11.61938	11.65063	11.65844	2.0250	1.285	11.750	.100	8
12	12.53282	12.61782	12.64907	12.65688	2.1250	1.360	12.750	.100	8
14 O. D.	13.7750	13.87262	13.90387	13.91168	2.250	1.562	14.00	.100	8
15 O. D.	14.76875	14.87418	14.90543	14.91324	2.350	1.687	15.00	.100	8
16 O. D.	15.76250	15.87575	15.90700	15.91481	2.450	1.812	16.00	.100	8
17 O. D.	16.75625	16.87500	16.90625	16.91406	2.550	1.900	17.00	.100	8
18 O. D.	17.7500	17.87500	17.90625	17.91406	2.650	2.000	18.00	.100	8
20 O. D.	19.73750	19.87031	19.90156	19.90937	2.850	2.125	20.00	.100	8
22 O. D.	21.72500	21.86562	21.89687	21.90468	3.050	2.250	22.00	.100	8
24 O. D.	23.71250	23.86093	23.89218	23.89999	3.250	2.375	24.00	.100	8

(By Permission of Crane Company.)

THAT IS SCREWED INTO VALVES OR FITTINGS TO MAKE A TIGHT JOINT



Size Inches	Dimension A Inches	Size Inches	Dimension A Inches
1/8	1/4	3 1/2	1 1/16
1/4	3/8	4	1 1/16
3/8	3/8	4 1/2	1 1/8
1/2	1/2	5	1 3/16
3/4	1/2	6	1 1/4
1	9/16	7	1 1/4
1 1/4	5/8	8	1 5/16
1 1/2	5/8	9	1 3/8
2	11/16	10	1 1/2
2 1/2	15/16	12	1 5/8
3	1		

DIMENSIONS GIVEN DO NOT ALLOW FOR VARIATION IN TAPPING OR THREADING

(By Permission of Crane Company.)

temperature of the fluid carried and the surrounding air, must be cared for by suitable expansion joints or bends.

In order to determine the amount of expansion or contraction in a pipe line, we give below a table showing the increase in length of a pipe 100 feet long at various temperatures.

The expansion for any length of pipe may be found by taking the difference in increased length at the minimum and maximum temperatures, dividing by 100 and multiplying by the length of the line under consideration.

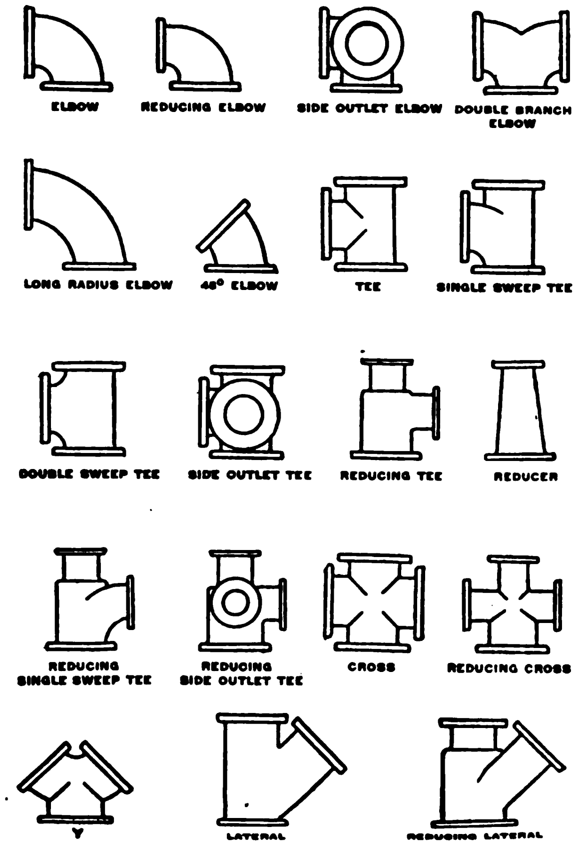
EXPANSION OF PIPE

INCREASE IN LENGTH—INCHES PER 100 FEET

Temperature, Degrees F.	Steel	Wrought Iron	Cast Iron	Brass and Copper
0	0	0	0	0
20	.15	.15	.10	.25
40	.30	.30	.25	.45
60	.45	.45	.40	.65
80	.60	.60	.55	.90
100	.75	.80	.70	1.15
20	.90	.95	.85	1.40
40	1.10	1.15	1.00	1.65
60	1.25	1.35	1.15	1.90
80	1.45	1.50	1.30	2.15
200	1.60	1.65	1.50	2.40
20	1.80	1.85	1.65	2.65
40	2.00	2.05	1.80	2.90
60	2.15	2.20	1.95	3.15
80	2.35	2.40	2.15	3.45
300	2.50	2.60	2.35	3.75
20	2.70	2.80	2.50	4.05
40	2.90	3.05	2.70	4.35
60	3.05	3.25	2.90	4.65
80	3.25	3.45	3.10	4.95
400	3.45	3.65	3.30	5.25
20	3.70	3.90	3.50	5.60
40	3.95	4.20	3.75	5.95
60	4.20	4.45	4.00	6.30
80	4.45	4.70	4.25	6.65
500	4.70	4.90	4.45	7.05
20	4.95	5.15	4.70	7.45
40	5.20	5.40	4.95	7.85
60	5.45	5.70	5.20	8.25
80	5.70	6.00	5.45	8.65
600	6.00	6.25	5.70	9.05
20	6.30	6.55	5.95	9.50
40	6.55	6.85	6.25	9.95
60	6.90	7.20	6.55	10.40
80	7.20	7.50	6.85	10.95
700	7.50	7.85	7.15	11.40
20	7.80	8.20	7.45	11.90
40	8.20	8.55	7.80	12.40
60	8.55	8.90	8.15	12.95
80	8.95	9.30	8.50	13.50
800	9.30	9.75	8.90	14.10

AMERICAN STANDARD

NAMES OF FITTINGS



TEMPLATES FOR DRILLING

EXTRA HEAVY HYDRAULIC CAST STEEL FLANGED VALVES AND FITTINGS

FOR COLD WATER OR OIL WORKING PRESSURES UP TO 3000 POUNDS HYDROSTATIC

Size	Diameter of Flanges	Thickness of Flanges	Diameter of Bolt Circle	Number of Bolts	Size of Bolts	Length of Bolts	Diameter of Male	Height of Male	Diameter of Female	Depth of Female
Inches	Inches	Inches	Inches		Inches	Inches	Inches	Inches	Inches	Inches
1½	6½	⅞	5	4	¾	2¾	2¼	3/16	2 5/16	⅛
2	7½	1	5¾	4	⅝	3¼	2¾	3/16	2 13/16	⅛
2½	8¾	1⅛	6½	8	¾	3½	3 1/16	3/16	3⅜	⅛
3	10	1¼	8	8	⅞	3¾	3 11/16	3/16	4	⅛
4	11½	1⅜	9¼	8	1⅛	4¼	5	3/16	5 5/16	⅛
5	13½	1 7/16	11	12	1⅛	4½	6 3/16	3/16	6¼	⅛
6	15	1½	12½	12	1¼	4¾	7¼	3/16	7 5/16	⅛

These Drilling Templates are in multiples of four, so that fittings may be made to face in any quarter, and bolt holes straddle the center line.

Bolt holes are drilled ⅛ inch larger than nominal diameter of bolts and are regularly furnished spot faced.

(By Permission of Crane Company.)

STANDARD AND LOW PRESSURE FLANGED VALVES AND FITTINGS

EFFECTIVE JANUARY 1, 1914

Size	Diameter of Flanges	Thickness of Flanges	Bolt Circle	Number of Bolts	Size of Bolts	Length of Bolts	Length of Studs with 2 Nuts
Inches	Inches	Inches	Inches		Inches	Inches	Inches
1	4	7/16	3	4	7/16	1½	
1¼	4½	½	3⅜	4	7/16	1½	
1½	5	9/16	3⅞	4	½	1¾	
2	6	⅝	4¾	4	⅝	2	
2½	7	11/16	5½	4	⅝	2¼	
3	7½	¾	6	4	⅝	2½	
3½	8½	13/16	7	4	⅝	2½	
4	9	15/16	7½	8	⅝	2¾	
4½	9¼	15/16	7¾	8	¾	2¾	
5	10	15/16	8½	8	¾	2¾	
6	11	1	9½	8	¾	3	
7	12½	1 1/16	10¾	8	¾	3	
8	13½	1⅛	11¾	8	¾	3¼	
9	15	1⅛	13¼	12	¾	3¼	
10	16	1 3/16	14¼	12	⅞	3½	
12	19	1¼	17	12	⅞	3½	
14	21	1⅜	18¾	12	1	4	
15	22¼	1⅜	20	16	1	4	
16	23½	1 7/16	21¼	16	1	4	
18	25	1 9/16	22¾	16	1⅛	4½	
20	27½	1 11/16	25	20	1⅛	4¾	
22	29½	1 13/16	27¼	20	1¼	5	
24	32	1⅞	29½	20	1¼	5¼	
26	34¼	2	31¾	24	1¼	5½	
28	36½	2 1/16	34	28	1¼	5½	
30	38¾	2⅛	36	28	1⅜	5¾	
32	41¾	2¼	38½	28	1½	6¼	
34	43¾	2 5/16	40½	32	1½	6½	
36	46	2⅜	42¾	32	1½	6½	
38	48¾	2⅜	45¼	32	1⅝	6¾	9
40	50¾	2½	47¼	36	1⅝	7	9

These Drilling Templates are in multiples of four, so that fittings may be made to face in any quarter and bolt holes straddle the center line.

Bolt holes are drilled ⅛ inch larger than nominal diameter of bolts.

CONTINUED

Size	Diameter of Flanges	Thickness of Flanges	Bolt Circle	Number of Bolts	Size of Bolts	Length of Bolts	Length of Studs with 2 Nuts
Inches	Inches	Inches	Inches		Inches	Inches	Inches
42	53	2⅝	49½	36	1⅝	7¼	9½
44	55¼	2⅝	51¾	40	1⅝	7¼	9½
46	57¼	2 11/16	53¾	40	1⅝	7½	9½
48	59½	2¾	56	44	1⅝	7½	9½
50	61¾	2¾	58¼	44	1¾	7¾	10
52	64	2⅞	60½	44	1¾	8	10½
54	66¼	3	62¾	44	1¾	8¼	10½
56	68¾	3	65	48	1¾	8¼	10½
58	71	3⅛	67¼	48	1¾	8½	11
60	73	3⅛	69¼	52	1¾	8½	11
62	75¾	3¼	71¾	52	1⅞	9	11½
64	78	3¼	74	52	1⅞	9	11½
66	80	3⅜	76	52	1⅞	9¼	11½
68	82¼	3⅜	78¼	56	1⅞	9¼	11½
70	84½	3½	80½	56	1⅞	9½	12
72	86½	3½	82½	60	1⅞	9½	12
74	88½	3⅝	84½	60	1⅞	9¾	12
76	90¾	3⅝	86½	60	1⅞	9¾	12
78	93	3¾	88¾	60	2	10	12½
80	95¼	3¾	91	60	2	10	12½
82	97½	3⅞	93¼	60	2	10½	13
84	99¾	3⅞	95½	64	2	10½	13
86	102	4	97¾	64	2	10½	13
88	104¼	4	100	68	2	10½	13
90	106½	4⅛	102¼	68	2⅛	11	14
92	108¾	4⅛	104½	68	2⅛	11	14
94	111	4¼	106¾	68	2¼	11¼	14
96	113¼	4¼	108½	68	2¼	11½	14½
98	115½	4⅜	110¾	68	2¼	11½	14½
100	117¾	4⅜	113	68	2¼	11½	14½

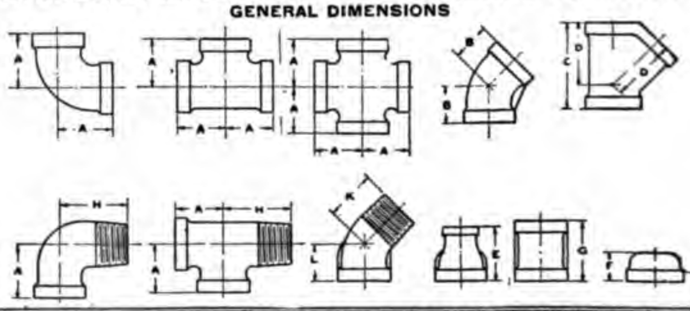
These Drilling Templates are in multiples of four, so that fittings may be made to face in any quarter and bolt holes straddle the center line.

Bolt holes are drilled ⅛ inch larger than nominal diameter of bolts.

(By Permission of Crane Company.)

STANDARD MALLEABLE IRON SCREWED FITTINGS

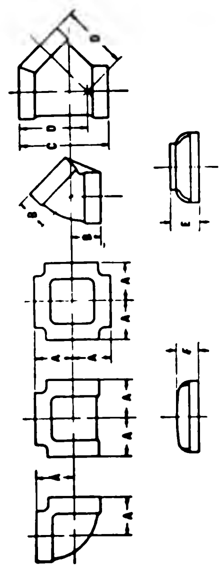
GENERAL DIMENSIONS



		1/8	1/4	3/8	1/2	3/4	1	1 1/4	1 1/2	2	2 1/2	3	3 1/2	4	4 1/2	5	6	7	8
Size	Inches	1/8	1/4	3/8	1/2	3/4	1	1 1/4	1 1/2	2	2 1/2	3	3 1/2	4	4 1/2	5	6	7	8
A	Inches	11/16	13/16	15/16	1 1/8	1 5/16	1 7/16	1 3/4	1 15/16	2 1/4	2 11/16	3 1/8	3 7/16	3 3/4	4 5/16	4 7/16	5 1/8	5 13/16	6 1/2
B	Inches		3/4	13/16	7/8	1	1 1/8	1 5/16	1 7/16	1 11/16	1 15/16	2 3/16	2 3/8	2 5/8	2 13/16	3 3/16	3 7/16	3 3/4	4 3/8
C	Inches				2 1/2	2 7/8	3 7/16	4 1/16	4 1/2	5 7/16	6 1/4	7 1/4		8 3/4					
D	Inches				1 11/16	2	2 7/16	2 13/16	3 5/16	4 1/16	4 15/16	5 7/16		6 13/16					
E	Inches		1	1 1/8	1 1/4	1 7/16	1 11/16	2 1/16	2 5/16	2 13/16	3 1/4	3 11/16	4	4 5/8					
F	Inches		5/8	3/4	7/8	1 1/16	1 3/16	1 1/4	1 5/16	1 7/16	1 5/8	1 3/4	1 13/16	2		2 3/16	2 7/16		
G	Inches		1 1/16	1 3/16	1 5/16	1 1/2	1 11/16	1 15/16	2 1/8	2 1/2	2 7/8	3 5/16							
H	Inches	1 1/8	1 3/16	1 7/16	1 5/8	1 7/8	2 1/8	2 1/2	2 13/16	3 5/16	3 13/16	4 1/2		5 13/16					
K	Inches		15/16	1 1/16	1 3/16	1 5/16	1 1/2	1 15/16	1 3/4	2 1/4		3		3 3/4					
L	Inches		11/16	13/16	15/16	15/16	1 1/16	1 1/4	1 3/8	1 11/16		2 1/8		2 1/2					

The above dimensions are subject to a slight variation and change without notice.

GENERAL DIMENSIONS OF STANDARD CAST IRON SCREWED FITTINGS



CAP

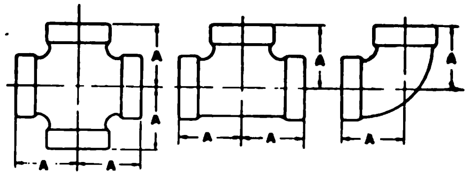
REDUCERS
REGULAR AND ECCENTRIC

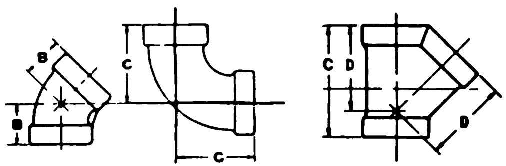
Size Inches	Dimensions A Inches	Dimensions B Inches	Dimension C Inches	Dimensions D Inches	Dimension E Inches	Dimension F Inches
1/4	11/16	3/4				
3/8	13/16	13/16				
1/2	1 1/8	7/8	2 1/2	1 7/8		
3/4	1 5/16	1	3	2 1/4		
1	1 7/16	1 1/8	3 1/2	2 3/4		
1 1/4	1 3/4	1 5/16	4 1/4	3 1/4	2 1/4	
1 1/2	1 15/16	1 7/16	4 7/8	3 15/16	2 5/8	
2	2 1/4	1 11/16	5 3/4	4 1/2	2 7/16	
2 1/2	2 11/16	1 15/16	6 1/4	5 3/16	2 13/16	
3	3 1/8	2 3/16	7 1/4	6 1/8	2 15/16	
3 1/2	3 7/16	2 3/8	8 7/8	6 7/8	3 1/8	
4	3 3/4	2 5/8	9 3/4	7 3/8	3 3/8	2 3/16
4 1/2	4 5/16	2 13/16	10 5/8	8 1/2	3 5/8	2 3/16
5	4 7/16	3 3/16	11 5/8	9 1/4	3 7/8	2 5/8
6	5 1/8	3 7/16	13 3/16	10 3/4	4 3/8	2 5/8
7	5 13/16	3 7/8	15 1/4	12 1/4	4 11/16	2 7/8
8	6 1/2	4 1/8	16 11/16	13 5/8	5 1/4	3 1/8
9	7 3/16	4 11/16	20 11/16	16 3/4	5 11/16	3 3/8
10	7 3/4	5 3/16	20 11/16	16 5/8	6 3/16	3 5/8
12	9 1/4	6	24 3/8	19 5/8	7 3/8	4 1/4

The above dimensions subject to a slight variation and change without notice.

CAST IRON
SCREWED FITTINGS

GENERAL DIMENSIONS



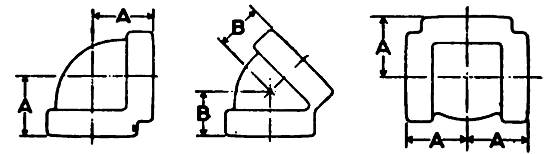


Size Inches	Dimensions A Inches	Dimensions B Inches	Dimensions C Inches	Dimensions D Inches
1	2	1⅜		
1¼	2¼	1½	4⅞	3 11/16
1½	2 9/16	1⅝	5¾	4½
2	3	1 13/16	6⅛	5 5/16
2½	3½	2¼	7⅝	6⅛
3	4⅛	2½	8⅞	6⅞
3½	4 11/16	2 9/16	9¾	7⅝
4	5⅛	2¾	10⅝	8½
4½	5½	3		
5	6 5/16	3 5/16		
6	7¼	3¾		
7	8⅝	4		
8	9⅝	4¾		
10	11⅜	4⅞		
12	13⅜	5½		

The above dimensions are subject to a slight variation and change without notice.

FORGED STEEL SCREWED FITTINGS

GENERAL DIMENSIONS



FOR COLD WATER OR OIL WORKING PRESSURES UP TO 3000 POUNDS PER SQUARE INCH HYDROSTATIC

No. 300 D. Elbows.
No. 301 D. Reducing Elbows.
No. 302 D. 45 Degree Elbows.
No. 304 D. Tees.
No. 306 D. Reducing Tees.

Size.....Inches	½	¾	1	1¼	1½	2	2½
A—Center to End. Elbows and Tees. Ins.	1½	1 5/16	1 7/16	1¾	1 15/16	2¼	2 11/16
B—Center to End. 45 Degree Elbows Ins.	1⅛	1 3/16	1 5/16	1 7/16	1 7/16	1 11/16	2 1/16

FOR COLD WATER OR OIL WORKING PRESSURES UP TO 6000 POUNDS PER SQUARE INCH HYDROSTATIC

No. 310 D, Elbows.
No. 311 D, Reducing Elbows.
No. 312 D, 45 Degree Elbows.
No. 314 D, Tees.
No. 316 D, Reducing Tees.

Size.....Inches	⅜	½	¾	1	1¼	1½	2
A—Center to End. Elbows and Tees.Ins.	1⅛	1 5/16	1 7/16	1⅝	1 15/16	2⅛	2 11/16
B—Center to End. 45 Degree Elbows.Ins.	1 1/16	1 1/16	1 1/16	1 3/16	1 7/16	1 11/16	2 1/16

REDUCING FITTINGS

Reducing Fittings have the same center to face dimensions as straight size fittings.

(By Permission of Crane Company.)

TEMPLATES FOR DRILLING

EXTRA HEAVY HYDRAULIC CAST STEEL FLANGED VALVES AND FITTINGS

FOR COLD WATER OR OIL WORKING PRESSURES UP TO 3000 POUNDS HYDROSTATIC

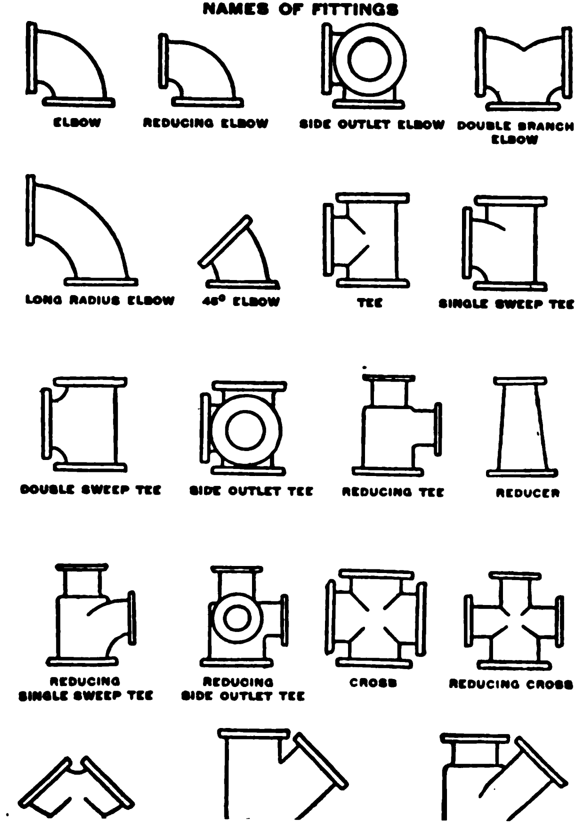
Size	Diameter of Flanges	Thickness of Flanges	Diameter of Bolt Circle	Number of Bolts	Size of Bolts	Length of Bolts	Diameter of Male	Height of Male	Diameter of Female	Depth of Female
Inches	Inches	Inches	Inches		Inches	Inches	Inches	Inches	Inches	Inches
1¼	6½	7/8	5	4	5/8	2¾	2¼	3/16	2 5/16	1/8
2	7½	1	5¾	4	5/8	3¼	2¾	3/16	2 13/16	1/8
2½	8¾	1⅛	6½	8	7/8	3½	3 3/16	3/16	3¼	1/8
3	10	1¼	8	8	7/8	3¾	3 15/16	3/16	4	1/8
4	11½	1⅜	9¼	8	1⅛	4¼	5	3/16	5 1/16	1/8
5	13½	1 7/16	11	12	1⅛	4½	6 3/16	3/16	6¼	1/8
6	15	1⅝	12½	12	1¼	4¾	7¼	3/16	7 5/16	1/8

These Drilling Templates are in multiples of four, so that fittings may be made to face in any quarter, and bolt holes straddle the center line.

Bolt holes are drilled ⅛ inch larger than nominal diameter of bolts and are regularly furnished spot faced.

(By Permission of Crane Company.)

AMERICAN STANDARD
NAMES OF FITTINGS



STANDARD AND LOW PRESSURE FLANGED VALVES ANDFITTINGS

EFFECTIVE JANUARY 1, 1914

Size	Diameter of Flanges	Thickness of Flanges	Bolt Circle	Number of Bolts	Size of Bolts	Length of Bolts	Length of Studs with 2 Nuts
Inches	Inches	Inches	Inches		Inches	Inches	Inches
1	4	7/16	3	4	7/16	1½	
1¼	4½	½	3⅜	4	7/16	1½	
1½	5	9/16	3⅞	4	½	1¾	
2	6	⅝	4¾	4	⅝	2	
2½	7	11/16	5½	4	⅝	2¼	
3	7½	¾	6	4	⅝	2½	
3½	8½	13/16	7	4	⅝	2½	
4	9	15/16	7½	8	⅝	2¾	
4½	9¼	15/16	7¾	8	¾	2¾	
5	10	15/16	8½	8	¾	2¾	
6	11	1	9½	8	¾	3	
7	12½	1 1/16	10¾	8	¾	3	
8	13½	1⅛	11¾	8	¾	3¼	
9	15	1⅛	13¼	12	¾	3¼	
10	16	1 3/16	14¼	12	⅞	3½	
12	19	1¼	17	12	⅞	3½	
14	21	1⅜	18¾	12	1	4	
15	22¼	1⅜	20	16	1	4	
16	23½	1 7/16	21¼	16	1	4	
18	25	1 9/16	22¾	16	1⅛	4½	
20	27½	1 11/16	25	20	1⅛	4¾	
22	29½	1 13/16	27¼	20	1¼	5	
24	32	1⅞	29½	20	1¼	5¼	
26	34¼	2	31¾	24	1¼	5½	
28	36½	2 1/16	34	28	1¼	5½	
30	38¾	2⅛	36	28	1⅜	5¾	
32	41¾	2¼	38½	28	1½	6¼	
34	43¾	2 5/16	40½	32	1½	6½	
36	46	2⅜	42¾	32	1½	6½	
38	48¾	2⅜	45¼	32	1⅝	6¾	9
40	50¾	2½	47¼	36	1⅝	7	9

These Drilling Templates are in multiples of four, so that fittings may be made to face in any quarter and bolt holes straddle the center line.

Bolt holes are drilled ⅛ inch larger than nominal diameter of bolts.

CONTINUED

Size	Diameter of Flanges	Thickness of Flanges	Bolt Circle	Number of Bolts	Size of Bolts	Length of Bolts	Length of Studs with 2 Nuts
Inches	Inches	Inches	Inches		Inches	Inches	Inches
42	53	2⅝	49½	36	1⅝	7¼	9½
44	55¼	2⅝	51¾	40	1⅝	7¼	9½
46	57¼	2 11/16	53¾	40	1⅝	7½	9½
48	59½	2¾	56	44	1⅝	7½	9½
50	61¾	2¾	58¼	44	1¾	7¾	10
52	64	2⅞	60½	44	1¾	8	10½
54	66¼	3	62¾	44	1¾	8¼	10½
56	68¾	3	65	48	1¾	8¼	10½
58	71	3⅛	67¼	48	1¾	8½	11
60	73	3⅛	69¼	52	1¾	8½	11
62	75¾	3¼	71¾	52	1⅞	9	11½
64	78	3¼	74	52	1⅞	9	11½
66	80	3⅜	76	52	1⅞	9¼	11½
68	82¼	3⅜	78¼	56	1⅞	9¼	11½
70	84½	3½	80½	56	1⅞	9½	12
72	86½	3½	82½	60	1⅞	9½	12
74	88½	3⅝	84½	60	1⅞	9¾	12
76	90¾	3⅝	86½	60	1⅞	9¾	12
78	93	3¾	88¾	60	2	10	12½
80	95¼	3¾	91	60	2	10	12½
82	97½	3⅞	93¼	60	2	10½	13
84	99¾	3⅞	95½	64	2	10½	13
86	102	4	97¾	64	2	10½	13
88	104¼	4	100	68	2	10½	13
90	106½	4⅛	102¼	68	2⅛	11	14
92	108¾	4⅛	104½	68	2⅛	11	14
94	111	4¼	106¾	68	2⅛	11¼	14
96	113¼	4¼	108½	68	2¼	11½	14½
98	115½	4⅜	110¾	68	2¼	11½	14½
100	117¾	4⅜	113	68	2¼	11½	14½

These Drilling Templates are in multiples of four, so that fittings may be made to face in any quarter and bolt holes straddle the center line.

Bolt holes are drilled ⅛ inch larger than nominal diameter of bolts.

(By Permission of Crane Company.)

TEMPLATES FOR DRILLING

EXTRA HEAVY AND MEDIUM FLANGED VALVES AND EXTRA HEAVY FLANGED FITTINGS

AMERICAN STANDARD

EFFECTIVE JANUARY 1, 1914

Size Inches	Diameter of Flanges Inches	Thickness of Flanges Inches	Bolt Circle Inches	Number of Bolts	Size of Bolts Inches	Length of Bolts Inches	Length of Studs with 2 Nuts Inches
1	4½	11/16	3¼	4	½	2	
1¼	5	¾	3½	4	½	2¼	
1½	6	13/16	4½	4	⅝	2½	
2	6½	⅞	5	4	⅝	2½	
2½	7½	1	5⅞	4	¾	3	
3	8¼	1⅛	6⅝	8	¾	3¼	
3½	9	1 3/16	7¼	8	¾	3¼	
4	10	1¼	7⅞	8	¾	3½	
4½	10½	1 5/16	8½	8	¾	3½	
5	11	1⅜	9¼	8	¾	3¾	
6	12½	1 7/16	10⅝	12	¾	3¾	
7	14	1½	11⅞	12	⅞	4	
8	15	1⅝	13	12	⅞	4¼	
9	16¼	1¾	14	12	1	4¾	
10	17½	1⅞	15¼	16	1	5	
12	20½	2	17¾	16	1⅛	5¼	
14	23	2⅛	20¼	20	1⅛	5½	
15	24½	2 3/16	21½	20	1¼	5¾	
16	25½	2¼	22½	20	1¼	6	
18	28	2⅜	24¾	24	1¼	6¼	
20	30½	2½	27	24	1⅜	6½	
22	33	2⅝	29¼	24	1½	7	
24	36	2¾	32	24	1⅝	7½	9½
26	38¼	2 13/16	34½	28	1⅝	7¾	10
28	40¾	2 15/16	37	28	1⅝	8	10
30	43	3	39¼	28	1¾	8¼	10½
32	45¾	3⅛	41½	28	1⅞	8½	11
34	47½	3¼	43½	28	1⅞	9	11½
36	50	3⅜	46	32	1⅞	9¼	11½
38	52¼	3 7/16	48	32	1⅞	9¼	11½
40	54½	3 9/16	50¼	36	1⅞	9½	12
42	57	3 11/16	52¾	36	1⅞	9¾	12
44	59¼	3¾	55	36	2	10	12½
46	61½	3⅞	57¼	40	2	10¼	13
48	65	4	60¾	40	2	10½	13

These Drilling Templates are in multiples of four, so that fittings may be made to face in any quarter, and bolt holes straddle the center line.

Bolt holes are drilled ⅛ inch larger than nominal diameter of bolts.

For Flanges with Male, Female Tongue or Grove Faces add ¼ inch to the bolt length given in table above.

For Cranelap Joints for each flange add the thickness of the pipe to the bolt length given in table above.

TEMPLATES FOR DRILLING

EXTRA HEAVY HYDRAULIC FERROSTEEL FLANGED VALVES AND FITTINGS

FOR COLD WATER OR OIL WORKING PRESSURES AS FOLLOWS:

1½ INCH TO 2½ INCH, 1200 POUNDS HYDROSTATIC

3 INCH TO 4 INCH, 1000 POUNDS HYDROSTATIC

4½ INCH TO 12 INCH, 800 POUNDS HYDROSTATIC

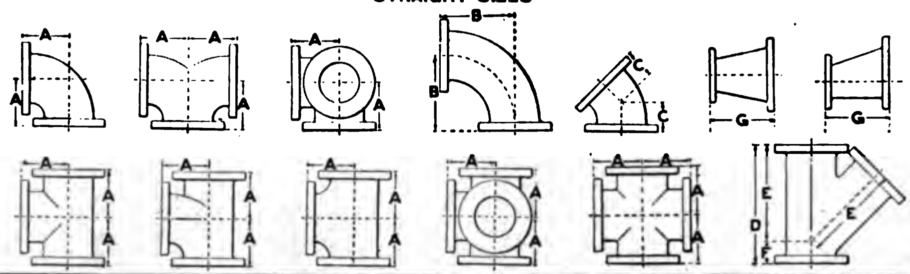
Size Inches	Diameter of Flanges Inches	Thickness of Flanges Inches	Diameter of Bolt Circle Inches	Number of Bolts	Size of Bolts Inches	Length of Bolts Inches	Diameter of Male Inches	Height of Male Inches	Diameter of Female Inches	Depth of Female Inches
1½	6½	1⅛	5	4	⅝	3¼	3⅛	3/16	3 3/16	⅛
2	7½	1¼	5¾	4	¾	3¾	3⅝	3/16	3 11/16	⅛
2½	8¾	1⅜	6½	8	¾	4	4⅛	3/16	4 3/16	⅛
3	10	1 7/16	8	8	¾	4¼	5	3/16	5 1/16	⅛
3½	10¾	1⅝	8½	8	⅞	4½	5½	3/16	5 9/16	⅛
4	11½	1 11/16	9⅜	8	1	4¾	6	3/16	6 1/16	⅛
4½	12½	1 13/16	10	12	1	5	6½	3/16	6 9/16	⅛
5	13½	1⅞	11	12	1	5¼	7¼	3/16	7 5/16	⅛
6	15	2 1/16	12½	12	1⅛	5¾	8⅜	3/16	8 7/16	⅛
7	16	2¼	13⅝	16	1⅛	6	9⅜	¼	9 7/16	3/16
8	17	2⅜	14⅝	16	1¼	6½	10⅝	¼	10 11/16	3/16
9	18½	2 7/16	15½	16	1¼	6¾	11⅝	¼	11 11/16	3/16
10	21	2¾	17¾	20	1¼	7¼	12¾	¼	12 13/16	3/16
12	23½	3⅛	20⅝	20	1⅜	8	15¼	¼	15 5/16	3/16

These Drilling Templates are in multiples of four, so that fittings may be made to face in any quarter and bolt holes straddle the center line.

Bolt holes are drilled ⅛ inch larger than nominal diameter of bolts.

(By Permission of Crane Company.)

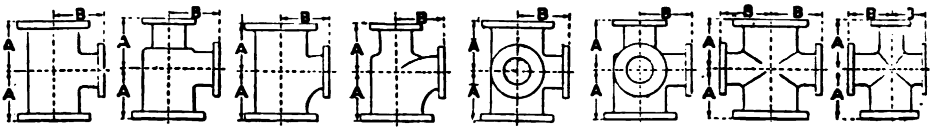
GENERAL DIMENSIONS OF
STANDARD AND LOW PRESSURE FLANGED FITTINGS
STRAIGHT SIZES



Size . . . . . . In.	1	1¼	1½	2	2½	3	3½	4	4½	5	6	7	8	9	10	12	14	15	16	18	20
A A–Face to Face, Tees and Crosses . In.	7	7½	8	9	10	11	12	13	14	15	16	17	18	20	22	24	28	29	30	33	36
A–C. to F., Elbows, Tees and Crosses . In.	3½	3¾	4	4½	5	5½	6	6½	7	7½	8	8½	9	10	11	12	14	14½	15	16½	18
B–C. to F., Long Radius Elbows . . . In.	5	5½	6	6½	7	7¾	8½	9	9½	10¼	11½	12¾	14	15¼	16½	19	21½	22¾	24	26½	29
C–Center to Face, 45° Elbows . . . In.	1¾	2	2¼	2½	3	3	3½	4	4	4½	5	5½	5½	6	6½	7½	7½	8	8	8½	9½
D–Face to Face, Laterals . . In.	7½	8	9	10½	12	13	14½	15	15½	17	18	20½	22	24	25½	30	33	34½	36½	39	43
E–Center to Face, Laterals . . . . In.	5¾	6¼	7	8	9½	10	11½	12	12½	13½	14½	16½	17½	19½	20½	24½	27	28½	30	32	35
F–Center to Face, Laterals . . . . In.	1¾	1¾	2	2½	2½	3	3	3	3	3½	3½	4	4½	4½	5	5½	6	6	6½	7	8
G–Face to Face, Reducers . In.						6	6½	7	7½	8	9	10	11	11½	12	14	16	17	18	19	20
Diameter of Flanges . . . . . In.	4	4½	5	6	7	7½	8½	9	9¼	10	11	12½	13½	15	16	19	21	22¼	23½	25	27½
Thickness of Flanges . . . . . In.	7/16	½	9/16	5/8	11/16	¾	13/16	15/16	15/16	15/16	1	1 1/16	1⅛	1⅛	1 3/16	1¼	1⅜	1⅜	1 7/16	1 9/16	1 11/16

(By Permission of Crane Company.)

STANDARD AND LOW PRESSURE FLANGED FITTINGS
GENERAL DIMENSIONS REDUCING TEES AND CROSSES



SHORT BODY PATTERN

Size . . . . In.	1	1¼	1½	2	2½	3	3½	4	4½	5	6	7	8	9	10	12	14	15	16	18	20	22	24	26	28	30	32	34	36	38	40
*Size of Outlet & Smlr. In.	All reducing fittings 1 inch to 16 inch, inclusive, have the same center to face dimensions as straight size fittings.																			12	14	15	16	18	18	20	20	22	24	24	28
AA–F. to F., Run . . . . In.																				26	28	28	30	32	32	36	36	38	40	40	44
A–C. to F., Run . . . . In.																				13	14	14	15	16	16	18	18	19	20	20	22
B–C. to F., Outlet . . . In.																				15½	17	18	19	20	21	23	24	25	26	28	29

Size . . . . In.	42	44	46	48	50	52	54	56	58	60	62	64	66	68	70	72	74	76	78	80	82	84	86	88	90	92	94	96	98	100	
Size of Outlet & Smlr. In.	28	28	30	32	32	34	36	36	38	40	40	42	44	44	46	48	48	50	52	52	54	56	56	58	60	60	62	64	64	66	
AA–F. to F., Run . . In.	46	46	48	52	52	54	58	58	62	66	66	68	70	70	74	80	80	84	86	86	88	94	94	96	100	100	104	106	106	110	
A–C. to F., Run . . . In.	23	23	24	26	26	27	29	29	31	33	33	34	35	35	37	40	40	42	43	43	44	47	47	48	50	50	52	53	53	55	
B–C. to F., Outlet . . In.	30	31	33	34	35	36	37	39	40	41	42	44	45	46	47	48	49	50	52	53	54	56	57	58	61	62	63	64	65	67	

***LONG BODY PATTERNS** {Are used when outlets are larger than given in the above table, therefore have same dimensions as straight size fittings.

The dimensions of "Reducing Flanged Fittings" are always regulated by the reduction of the outlet.

FITTINGS REDUCING ON THE RUN ONLY, the long body pattern will always be used, EXCEPT DOUBLE SWEEP TEES, on which the reduced end is always longer than the regular fittings. Dimensions on request.

BULL HEADS OR TEES having outlets larger than the run, will be the same length center to face of all openings as a Tee with all openings of the size of the outlet. For example, a 12 x 12 x 18 inch Tee will be governed by the dimensions of the 18 inch Long Body Tee, namely, 16½ inches center to face of all openings and 33 inches face to face.

REDUCING ELBOWS carry same center to face dimension as regular elbows of largest straight size.

GENERAL DIMENSIONS OF

STANDARD AND LOW PRESSURE FLANGED FITTINGS

STRAIGHT SIZES

CONTINUED FROM OPPOSITE PAGE

Size . . . . In.	22	24	26	28	30	32	34	36	38	40	42	44	46	48	50	52	54	56	58	60	62
AA–Face to Face, Tees and Crosses. In.	40	44	46	48	50	52	54	56	58	60	62	64	66	68	70	74	78	82	84	88	90
A–C. to F., Elbows, Tees and Crosses. In.	20	22	23	24	25	26	27	28	29	30	31	32	33	34	35	37	39	41	42	44	45
B–C. to F., Long Radius Elbows. . . . In.	31½	34	36½	39	41½	44	46½	49	51½	54	56½	59	61½	64	66½	69	71½	74	76½	79	81½
C–Center to Face, 45° Elbows. . . . In.	10	11	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
D–Face to Face, Laterals. In.	46	49½	53	56	59																
E–Center to Face, Laterals. In.	37½	40½	44	46½	49																
F–Center to Face, Laterals. In.	8½	9	9	9½	10																
G–Face to Face, Reducers. In.	22	24	26	28	30	32	34	36	38	40	42	44	46	48	50	52	54	56	58	60	62
Diameter of Flanges . . In.	29½	32	34¼	36½	38¾	41¼	43¾	46	48¾	50¾	53	55¼	57¼	59½	61¾	64	66¼	68¾	71	73	75¼
Thickness of Flanges . . . . In.	1 11/16	1¾	2	2 1/16	2⅛	2¼	2 5/16	2⅜	2⅜	2½	2⅝	2⅝	2 11/16	2¾	2¾	2⅞	3	3	3⅛	3⅛	3¼

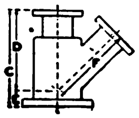
Size . . . . In.	64	66	68	70	72	74	76	78	80	82	84	86	88	90	92	94	96	98	100		
AA–Face to Face, Tees and Crosses. In.	94	96	100	102	106	108	112	116	118	120	124	126	130	134	136	138	142	146	148		
A–C. to F., Elbows, Tees and Crosses. In.	47	48	50	51	53	54	56	58	59	60	62	63	65	67	68	69	71	73	74		
B–C. to F., Long Radius Elbows. . . In.	84	86½	89	91½	94	96½	99	101¼	104	106¼	109	111¼	114	116¼	119	121¼	124	126¼	129		
C–Center to Face, 45° Elbows . . In.	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50		
G–Face to Face, Reducers. In.	64	66	68	70	72	74	76	78	80	82	84	86	88	90	92	94	96	98	100		
Diameter of Flanges . . . . . In.	78	80	82¼	84½	86½	88½	90¾	93	95¼	97½	99¾	102	104¼	106¼	108½	111	113¼	115¼	117½		
Thickness of Flanges . . . . . In.	3⅜	3⅜	3⅜	3½	3½	3⅝	3⅝	3¾	3¾	3⅞	3⅞	4	4	4⅛	4⅛	4¼	4¼	4⅜	4⅜		

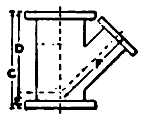
Standard and Low Pressure Flanged Fittings are furnished plain faced unless otherwise ordered.

(By Permission of Crane Company.)

STANDARD AND LOW PRESSURE FLANGED FITTINGS

GENERAL DIMENSIONS REDUCING LATERALS





SHORT BODY PATTERN

Size . . . . In.	1	1¼	1½	2	2½	3	3½	4	4½	5	6	7	8	9	10	12	14	15	16	18	20	22	24	26	28	30
*Size of Branch and Smaller. In.																				9	10	10	12	12	14	15
C–Face to Face, Run . . . . . . In.	All reducing fittings 1 to 16 inch, inclusive, have same center to face dimensions as straight size fittings.																			26	28	29	32	35	37	39
D–Center to Face, Run . . . . In.																				25	27	28½	31¼	35	37	39
E–Center to Face, Run . . . . In.																				1	1	½	½	0	0	0
F–Center to Face, Branch. . In.																				27½	29½	31½	34½	38	40	42

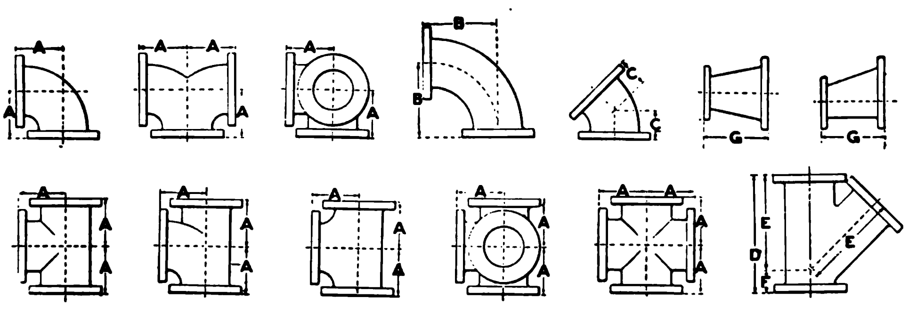
*LONG BODY PATTERNS { Are used when branches are larger than given in the above table, therefore have same dimensions as straight size fittings.

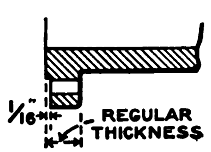
The dimensions of Reducing Flanged Fittings are always regulated by the reduction of the branch; fittings reducing on the run only, the long body pattern will always be used.

EXTRA HEAVY FLANGED FITTINGS

CAST IRON, FERROSTEEL AND CAST STEEL

STRAIGHT SIZES





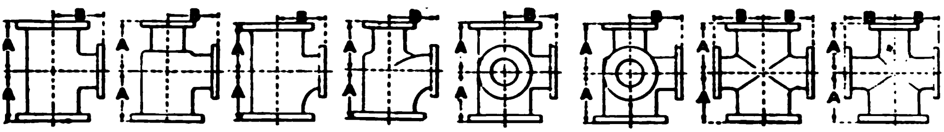
NOTE.—All extra heavy flanges have a $\frac{1}{16}$ inch Raised Face inside of bolt holes. This Raised Face is included in face to face, center to face and thickness of flange dimensions.

(By Permission of Crane Company.)

EXTRA HEAVY FLANGED FITTINGS

CAST IRON, FERROSTEEL AND CAST STEEL

GENERAL DIMENSIONS REDUCING TEES AND CROSSES



SHORT BODY PATTERN

All reducing fittings 1 inch to 16 inch, inclusive, have the same center to face dimensions as straight size fittings.

Size.......................In.	18	20	22	24	26	28	30	32	34	36	38	40	42	44	46	48
*Size of Outlet and Smaller..........In.	12	14	15	16	18	18	20	20	22	24	24	26	28	28	30	32
AA–Face to Face, Run..........In.	26	31	33	34	38	38	41	41	44	47	47	50	53	53	55	58
A–Center to Face, Run..........In.	14	15½	16½	17	19	19	20½	20½	22	23½	23½	25	26½	26½	27½	29
B–Center to Face, Outlet..........In.	17	18½	20	21½	23	24	25½	26½	28	29½	30½	31½	33½	34½	35½	37½

*LONG BODY PATTERNS {Are used when outlets are larger than given in the above table, therefore have same dimensions as straight size fittings.

The dimensions of "Reducing Flanged Fittings" are always regulated by the reduction of the outlet.

FITTINGS REDUCING ON THE RUN ONLY, the long body pattern will always be used, EXCEPT DOUBLE SWEEP TEES, on which the reduced end is always longer than the regular fitting. Dimensions on request.

BULL HEADS OR TEES having outlets larger than the run, will be the same length center to face of all openings as a Tee with all openings of the size of the outlet. For example, a 12 x 12 x 18 inch Tee will be governed by the dimensions of the 18 inch Long Body Tee, namely, 18 inches center to face of all openings and 36 inches face to face.

REDUCING ELBOWS carry same center to face dimension as regular elbows of largest straight size.

GENERAL DIMENSIONS

EXTRA HEAVY FLANGED FITTINGS

CAST IRON, FERROSTEEL AND CAST STEEL

STRAIGHT SIZES

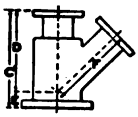
Size.......................In.	1	1¼	1½	2	2½	3	3½	4	4½	5	6	7	8	9	10	12	14	15
AA–Face to Face, Tees and Crosses...In.	8	8½	9	10	11	12	13	14	15	16	17	18	20	21	23	26	30	31
A–Center to Face, Elbows, Tees and Crosses........In.	4	4¼	4½	5	5½	6	6½	7	7½	8	8½	9	10	10½	11½	13	15	15½
B–Center to Face, Long Radius Elbows.In.	5	5½	6	6½	7	7¾	8½	9	9½	10¼	11½	12¾	14	15¼	16½	19	21½	22¾
C–Center to Face, 45° Elbows.........In.	2	2½	2¾	3	3¼	3½	4	4¼	4½	5	5½	6	6	6½	7	8	8½	9
D–Face to Face, Laterals.............In.	8½	9½	11	11½	13	14	15½	16½	18	18½	21½	23½	25½	27½	29½	33½	37½	39½
E–Center to Face, Laterals...........In.	6½	7¼	8½	9	10½	11	12½	13½	14½	15	17½	19	20½	22½	24	27½	31	33
F–Center to Face, Laterals...........In.	2	2¼	2½	2½	2½	3	3	3	3½	3½	4	4½	5	5	5½	6	6½	6½
G–Face to Face, Reducers...........In.						6	6½	7	7½	8	9	10	11	11½	12	14	16	17
Diameter of Flanges.................In.	4½	5	6	6½	7½	8¼	9	10	10½	11	12½	14	15	16¼	17½	20½	23	24¾
Thickness of Flanges...............In.	11/16	¾	13/16	⅞	1	1⅛	1 3/16	1¼	1 5/16	1⅜	1 7/16	1½	1⅝	1¾	1⅞	2	2¼	2⅜
Size.......................In.	16	18	20	22	24	26	28	30	32	34	36	38	40	42	44	46	48	
AA–Face to Face, Tees and Crosses...In.	33	36	39	41	45	48	52	55	58	61	65	68	71	74	78	81	84	
A–Center to Face, Elbows, Tees and Crosses........In.	16½	18	19½	20½	22½	24	26	27½	29	30½	32½	34	35½	37	39	40½	42	
B–Center to Face, Long Radius Elbows.In.	24	26½	29	31½	34	36½	39	41½	44	46½	49	51½	54	56½	59	61½	64	
C–Center to Face 45° Elbows..........In.	9½	10	10½	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
D–Face to Face, Laterals.............In.	42	45½	49	53	57½													
E–Center to Face, Laterals...........In.	34½	37½	40½	43½	47½													
F–Center to Face, Laterals...........In.	7½	8	8½	9½	10													
G–Face to Face, Reducers............In.	18	19	20	22	24	26	28	30	32	34	36	38	40	42	44	46	48	
Diameter of Flanges.................In.	25½	28	30½	33	36	38¼	40¾	43	45¾	47½	50	52¾	54½	57	59¼	61½	65	
Thickness of Flanges...............In.	2½	2¾	2½	2¾	2¾	2 13/16	2 15/16	3	3¼	3¼	3⅜	3 7/16	3 9/16	3 11/16	3¾	3⅞	4	

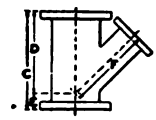
(By Permission of Crane Company.)

EXTRA HEAVY FLANGED FITTINGS

CAST IRON, FERROSTEEL AND CAST STEEL

GENERAL DIMENSIONS REDUCING LATERALS





SHORT BODY PATTERN

Size.........In.	1	1 1/4	1 1/2	2	2 1/2	3	3 1/2	4	4 1/2	5	6	7	8	9	10	12	14	15	16	18	20	22	24
*Size of Branch and Smaller.In.	All reducing fittings 1 to 16 inch, inclusive, have same center to face dimensions as straight size fittings.																			9	10	10	12
C—Face to Face, Run....In.																				34	37	40	44
D—Center to Face, Run..In.																				31	34	37	41
E—Center to Face, Run..In.																				3	3	3	3
F—Center to Face, Branch.In.																				32 1/2	36	39	43

*LONG BODY PATTERNS {Are used when branches are larger than given in the above table, therefore have same dimensions as straight size fittings.

The dimensions of Reducing Flanged Fittings are always regulated by the reduction of the branch; fittings reducing on the run only, the long body pattern will always be used.

EXTRA HEAVY HYDRAULIC

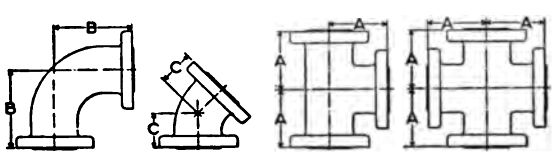
FERROSTEEL FLANGED FITTINGS

FOR COLD WATER OR OIL WORKING PRESSURES AS FOLLOWS:

1 1/2 TO 2 1/2 INCH, 1200 LBS. HYDROSTATIC; 3 TO 4 INCH, 1000 LBS. HYDROSTATIC; 4 1/2 TO 12 INCH, 800 LBS. HYDROSTATIC

TESTED TO 2000 POUNDS HYDRAULIC PRESSURE

GENERAL DIMENSIONS OF STRAIGHT SIZES



Size.........Inches	1 1/2	2	2 1/2	3	3 1/2	4	4 1/2	5	6	7	8	9	10	12
AA-Face to Face, Tees and Crosses.........Inches	11	12	13	15	16	17	19	20	22	23	25	27	30	33
A—Center to Face, Tees and Crosses.........Inches	5 1/2	6	6 1/2	7 1/2	8	8 1/2	9 1/2	10	11	11 1/2	12 1/2	13 1/2	15	16 1/2
B—Center to Face, Elbows.........Inches	7 1/4	8	8 3/4	9 1/2	10	10 3/4	12 1/2	13 3/4	15	16 1/2	17 3/4	20 3/4	22 3/4	24 3/4
C—Center to Face, 45° Elbows.........Inches	3 1/4	3 1/2	4	4 1/2	5	5 1/4	5 1/2	6	6 1/2	7	7 1/4	7 3/4	8 1/2	9 1/2
Diameter of Flanges.........Inches	6 1/2	7 1/2	8 3/4	10	10 3/4	11 1/2	12 1/2	13 1/2	15	16	17	18 1/2	21	23 1/2
Thickness of Flanges.........Inches	1 1/8	1 1/4	1 3/8	1 7/16	1 5/8	1 11/16	1 13/16	1 7/8	2 1/16	2 1/4	2 3/8	2 7/16	2 3/4	3 1/8

(By Permission of Crane Company.)

STANDARD COMPANION FLANGES

CAST IRON, FERROSTEEL. FORGED STEEL AND MALLEABLE IRON

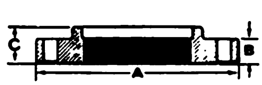
GENERAL DIMENSIONS

Size............Inches	3/4	1	1 1/4	1 1/2	2	2 1/2	3	3 1/2	4	4 1/2	5	6	7	8	9	10	12	14	15	16	18	20	22	24
A—Diameter of Flange. Inches	3 1/2	4	4 1/2	5	6	7	7 1/2	8 1/2	9	9 1/4	10	11	12 1/2	13 1/2	15	16	19	21	22 1/4	23 1/2	25	27 1/2	29 1/2	33
B—Thickness of Flange. Inches	7/16	7/16	1/2	9/16	5/8	11/16	3/4	13/16	15/16	15/16	15/16	1	1 1/16	1 1/8	1 1/8	1 3/16	1 1/4	1 3/8	1 3/8	1 7/16	1 9/16	1 11/16	1 13/16	1 7/8
C—Length of Hub.... Inches	5/8	11/16	3/4	7/8	1	1 1/16	1 1/8	1 3/16	1 3/16	1 1/4	1 5/16	1 5/16	1 1/2	1 5/8	1 3/4	1 7/8	2 1/16	2 3/16	2 3/16	2 5/16	2 5/8	2 5/8	2 3/4	3

EXTRA HEAVY COMPANION FLANGES

CAST IRON, MALLEABLE IRON, FERROSTEEL, CAST STEEL, FORGED STEEL

GENERAL DIMENSIONS



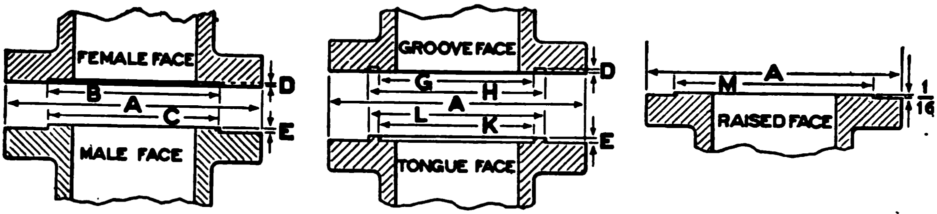
Size............Inches	1	1 1/4	1 1/2	2	2 1/2	3	3 1/2	4	4 1/2	5	6	7	8	9	10	12	14	15	16	18	20	22	24
A—Diameter of Flange. Inches	4 1/2	5	6	6 1/2	7 1/2	8 1/4	9	10	10 1/2	11	12 1/2	14	15	16 1/4	17 1/2	20 1/2	23	24 1/2	25 1/2	28	30 1/2	33	36
B—Thickness of Flange. Inches	11/16	3/4	13/16	7/8	1	1 1/8	1 3/16	1 1/4	1 5/16	1 3/8	1 7/16	1 1/2	1 5/8	1 3/4	1 7/8	2	2 1/8	2 3/16	2 1/4	2 3/8	2 1/2	2 5/8	2 3/4
C—Length of Hub... Inches	1	1 1/16	1 1/8	1 3/16	1 5/16	1 7/16	1 9/16	1 3/4	1 13/16	1 7/8	2	2 1/16	2 3/16	2 1/4	2 3/8	2 9/16	2 11/16	2 13/16	2 7/8	3 1/16	3 3/16	3 5/16	3 1/2

(By Permission of Crane Company.)

EXTRA HEAVY FLANGES

CAST IRON, FERROSTEEL AND CAST STEEL

GENERAL DIMENSIONS OF VARIOUS FACINGS

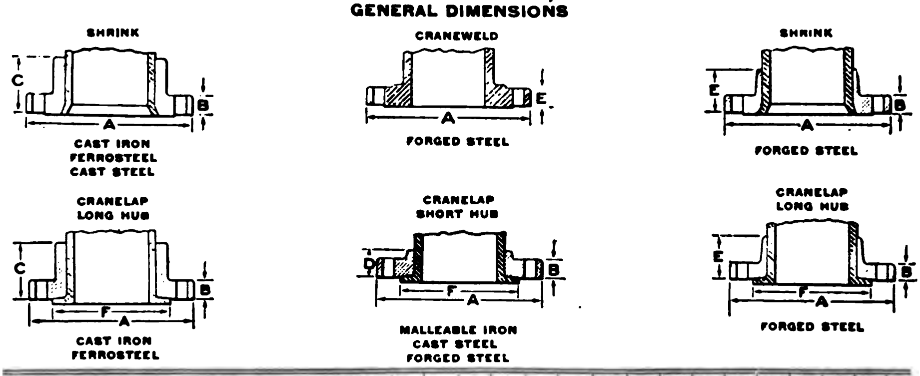


Size . . . . Inches	1	1¼	1½	2	2½	3	3½	4	4½	5	6	7	8	9	10	12	14	15	16	18	.20	22	24
A—Diameter of Flange . . . . Inches	4½	5	6	6½	7½	8¼	9	10	10½	11	12½	14	15	16¼	17½	20½	23	24½	25½	28	30½	33	36
B—Diameter Recess, Female . . Inches	2⅝	2 11/16	3 3/16	3 11/16	4 3/16	5 1/16	5 9/16	6 1/16	6 9/16	7 5/16	8 9/16	9 11/16	10 11/16	11 11/16	12 11/16	15 5/16	16 9/16	17 9/16	18 9/16	21 1/16	23 1/16	25 9/16	27 9/16
C—Diameter of Male . . . . Inches	2 9/16	2¾	3⅛	3⅝	4⅛	5	5½	6	6½	7¼	8½	9⅝	10⅝	11⅝	12¾	15¼	16½	17½	18½	21	23	25½	27½
D—Depth of Recess . . . . Inches	⅛	⅛	⅛	⅛	⅛	⅛	⅛	⅛	⅛	⅛	⅛	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16
E—Height of Face . . . . Inches	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16	3/16	¼	¼	¼	¼	¼	¼	¼	¼	¼	¼	¼	¼
G—Inside Diameter Groove . . Inches	1 11/16	2 1/16	2 11/16	3 1/16	3 9/16	4 3/16	4 11/16	5 3/16	5 11/16	6 9/16	7 1/16	8 9/16	9 3/16	10 9/16	11 9/16	13 9/16	15 11/16	17 1/16	18 9/16	20 9/16	22¼	24 1/16	26 1/16
H—Outside Diameter Groove . . Inches	2 9/16	3 1/16	3 11/16	4 9/16	4 11/16	5 9/16	5 11/16	6 9/16	6 11/16	7 9/16	8 9/16	9 11/16	10 11/16	11 11/16	13 3/16	15 5/16	17 1/16	18 11/16	20 9/16	22 1/16	24⅝	26 9/16	28 9/16
K—Inside Diameter Tongue . . Inches	1¾	2⅛	2¾	3⅛	3⅝	4⅛	4¾	5¼	5¾	6¼	7½	8⅝	9⅝	10½	11⅝	13⅝	15⅞	17⅛	18⅝	20⅝	22 9/16	24½	26½
L—Outside Diameter Tongue . . Inches	2½	3	3⅝	4⅛	4⅝	5¼	5¾	6¼	6¾	7¼	8½	9⅝	10⅞	11⅞	13⅛	15⅛	17⅝	18⅝	20⅛	22⅜	24 9/16	26½	28½
M—Diameter of Raised Face . . Inches	2 9/16	3 1/16	3 11/16	4 3/16	4 11/16	5 11/16	6 3/16	6 11/16	7 9/16	8 9/16	9 11/16	10 11/16	11 11/16	12 11/16	4 9/16	16 1/16	18 11/16	20 9/16	21 1/16	23 9/16	25 1/16	27 9/16	30 9/16

EXTRA HEAVY FLANGES

CRANELAP CRANEWELD SHRINK

GENERAL DIMENSIONS



Size . . . . Inches	4	4½	5	6	7	8	9	10	12	14	15	16	18	20	22	24
A—Diameter of Flange . . . . Inches	10	10½	11	12½	14	15	16¼	17½	20½	23	24½	25½	28	30½	33	36
B—Thickness of Flange . . . . Inches	1¼	1 5/16	1⅜	1 7/16	1½	1⅝	1¾	1⅞	2	2⅛	2 3/16	2¼	2⅜	2½	2⅝	2¾
C—Length of Hub, Regular . . . . Inches	3¾	3 13/16	4⅛	4¼	4 7/16	4⅝	4 13/16	4 15/16	5 3/16	5½	5⅝	6	6¼	6½	6⅞	7¼
D—Length of Hub, Short . . . . Inches	1¾	1 13/16	1⅞	2	2 1/16	2 3/16	2¼	2⅜	2 9/16	2 11/16	2 13/16	2⅞	3 1/16	3¼	3 7/16	3⅝
E—Length of Hub, Forged Steel . . . . Inches	3¼	3 5/16	3⅜	3 7/16	3 9/16	3¾	3 15/16	4⅛	4⅜	4⅝	4⅞	5⅛	5⅜	5⅝	6⅛	6 7/16
F—Diameter of Lap . . . . Inches	6⅝	7¼	7¾	9	10	11	12¼	43½	15¾	17¾	18½	19½	21½	23½	25½	27½

(By Permission of Crane Company.)

EXTRA HEAVY HYDRAULIC

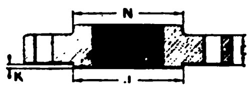
COMPANION FLANGES

FERROSTEEL — MALE OR FEMALE

GENERAL DIMENSIONS

FOR COLD WATER OR OIL WORKING PRESSURES AS FOLLOWS:

1½ TO 2½ INCH, 1200 LBS. HYDROSTATIC; 3 TO 4 INCH, 1000 LBS. HYDROSTATIC; 4½ TO 12 INCH, 800 LBS. HYDROSTATIC



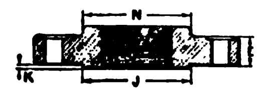
Size	Inches	1½	2	2½	3	3½	4	4½
B—Diameter of Flange	Inches	6½	7½	8¾	10	10¾	11½	12½
E—Thickness of Flange	Inches	1⅛	1¼	1⅜	1 7/16	1⅝	1 11/16	1 13/16
L—Diameter of Female	Inches	3 3/16	3 11/16	4 3/16	5 1/16	5 9/16	6 1/16	6 9/16
M—Depth of Female	Inches	⅛	⅛	⅛	⅛	⅛	⅛	⅛
J—Diameter of Male	Inches	3⅛	3⅝	4⅛	5	5½	6	6½
K—Thickness of Male	Inches	3/16	3/16	3/16	3/16	3/16	3/16	3/16
N—Diameter of Hub	Inches	3¼	3¾	4¼	4⅞	5½	6	6⅝
Size	Inches	5	6	7	8	9	10	12
B—Diameter of Flange	Inches	13½	15	16	17	18½	21	23½
E—Thickness of Flange	Inches	1⅞	2 1/16	2¼	2⅜	2 9/16	2¾	3⅛
L—Diameter of Female	Inches	7 5/16	8 5/16	9 7/16	10 11/16	11 11/16	12 11/16	15 5/16
M—Depth of Female	Inches	⅛	⅛	3/16	3/16	3/16	3/16	3/16
J—Diameter of Male	Inches	7¼	8¼	9⅜	10⅝	11⅝	12⅝	15¼
K—Thickness of Male	Inches	3/16	3/16	¼	¼	¼	¼	¼
N—Diameter of Hub	Inches	7¼	8¼	9½	10⅝	11⅝	13	15⅛

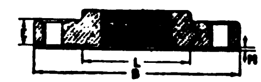
EXTRA HEAVY HYDRAULIC

CAST STEEL COMPANION FLANGES

GENERAL DIMENSIONS

FOR COLD WATER OR OIL WORKING PRESSURES UP TO 3000 POUNDS HYDROSTATIC





Size	Inches	1½	2	2½	3	4	5	6
B—Diameter of Flange	Inches	6½	7½	8¾	10	11½	13½	15
E—Thickness of Flange	Inches	⅞	1	1⅛	1¼	1⅜	1 7/16	1⅝
L—Diameter of Female	Inches	2 5/16	2 11/16	3⅜	4	5 1/16	6¼	7 5/16
M—Depth of Female	Inches	⅛	⅛	⅛	⅛	⅛	⅛	⅛
J—Diameter of Male	Inches	2¼	2¾	3 5/16	3 15/16	5	6 3/16	7¼
K—Thickness of Male	Inches	3/16	3/16	3/16	3/16	3/16	3/16	3/16
N—Diameter of Hub	Inches	2⅞	3 5/16	4	4⅝	5¾	6¾	7 11/16

(By Permission of Crane Company.)

STRENGTH OF BOLTS*

Diameter of Bolts	Number of Threads per Inch	Areas		Tensile Stress			Shearing Stress			
							Full Bolt		Bottom of Thread	
		Full Bolt	Bottom of Threads	10,000 Lbs. per Sq. Inch	12,500 Lbs. per Sq. Inch	17,500 Lbs. per Sq. Inch	7,500 Lbs. per Sq. Inch	10,000 Lbs. per Sq. Inch	7,500 Lbs. per Sq. Inch	10,000 Lbs. Per Sq. Inch
Inches		Sq. Inches	Sq. Inches	Pounds	Pounds	Pounds	Pounds	Pounds	Pounds	Pounds
1/4	20	.049	.027	270	340	470	380	490	200	270
5/16	18	.077	.045	450	570	790	580	770	340	450
3/8	16	.110	.068	680	850	1,190	830	1,100	510	680
7/16	14	.150	.093	930	1,170	1,630	1,130	1,500	700	930
1/2	12	.196	.120	1,200	1,500	2,100	1,470	1,960	900	1,200
9/16	12	.248	.162	1,620	2,030	2,840	1,860	2,480	1,220	1,620
5/8	11	.307	.202	2,020	2,520	3,530	2,300	3,070	1,510	2,020
3/4	10	.442	.302	3,020	3,770	5,290	3,310	4,420	2,270	3,020
7/8	9	.601	.419	4,190	5,240	7,340	4,510	6,010	3,150	4,190
1	8	.785	.551	5,510	6,890	9,640	5,890	7,850	4,130	5,510
1 1/8	7	.994	.693	6,930	8,660	12,130	7,450	9,940	5,200	6,930
1 1/4	7	1.227	.890	8,890	11,120	15,570	9,200	12,270	6,670	8,900
1 3/8	6	1.485	1.054	10,540	13,180	18,450	11,140	14,850	7,910	10,540
1 1/2	6	1.767	1.294	12,940	16,170	22,640	13,250	17,670	9,700	12,940
1 5/8	5 1/2	2.074	1.515	15,150	18,940	26,510	15,550	20,740	11,360	15,150
1 3/4	5	2.405	1.745	17,450	21,800	30,520	18,040	24,050	13,080	17,440
1 7/8	5	2.761	2.049	20,490	25,610	35,860	20,710	27,610	15,370	20,490
2	4 1/2	3.142	2.300	23,000	28,750	40,250	23,560	31,420	17,250	23,000
2 1/4	4 1/2	3.967	3.021	30,210	37,770	52,870	29,820	39,760	22,660	30,210
2 1/2	4	4.909	3.716	37,160	46,450	65,040	36,820	49,090	27,870	37,160

(By Permission of Crane Company.)

SUBJECT INDEX